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Impacts of short-duration batteries on Great Britain’s electrical power system and networks

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This thesis is the result of the author's original research. It has been composed by the author and has not been previously submitted for examination which has led to the award of a degree.

Signed:

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Abstract

This work considers the potential for flexibility providers in general, and batteries specifically, to lower the cost of the Great Britain (GB)'s electricity system, by reducing the amount of network reinforcement that would otherwise be necessary.

In GB, batteries and other storage assets engage in numerous activities, among them, wholesale trades, an activity this work simulates for case study periods during 2022.

The hypothesis: "*a rational battery, engaged in wholesale trades, will not export at times of high wind energy availability in Scotland, nor will it add to transmission network congestion*" was investigated and clearly found against.

A second hypothesis *"deployment of suitably-sized distribution-connected batteries, engaged in wholesale electricity trades, will not increase congestion on distribution networks servicing residential load demand and windfarms"* was investigated at six locations in southern Scotland, and also found against, regarding both import and export flows.

Given these findings, unfortunate especially for bill-payers, a possible mitigation, "non-firm" connections for batteries, was explored. This work found that, in most of the six above distribution locations studied, batteries could be significantly oversized, by up to 10 – 20 MW, compared to network spare capacity, before experiencing significant financial detriment from curtailment.

Finally, this work investigates whether battery-triggered network reinforcement, or battery curtailment, might be the "lower overall cost" option, at the case study locations studied. A range of battery sizes for which battery curtailment would appear to be the "lower cost" option was identified, together with relevant sensitivities. This consideration is complicated by the different parties on which the costs would fall, and identification of the appropriate comparison: "reinforce or not?", or "reinforce sooner or later?" The work also considered to what extent current arrangements encourage a "lowest overall cost approach", and whether that is even the most pertinent consideration, given that both network reinforcement, and also addition of batteries, could potentially provide wider value for other connecting customers, and for network operability.

The work concludes by answering the research questions posed, suggesting further work, and proposing some recommendations for policy makers.

Extended summary

This work considers the potential for flexibility, generally, and batteries, specifically, to lower the cost of the GB electricity system as it decarbonises, by reducing the amount of network reinforcement that would otherwise be necessary. This work is timely because there are currently many tens of GW of batteries with connection agreement to both distribution and transmission networks. Better understanding of how these batteries are likely to behave, especially in areas of network constraints, will aid owners and operators of the transmission and distribution networks, and the whole system, prepare for the very challenging transition to decarbonisation.

This work sets out to answer the following research questions:

Q1: What kinds of behaviours are foreseeable from short duration batteries?

Q2: Are expected behaviours of short-duration batteries likely to alleviate or exacerbate network congestion and system needs?

Q3: Is a large-scale roll-out of batteries likely to facilitate or obstruct deployment of renewable / low carbon generation, and the electricity system's transition to Net Zero?

Q4: If there are any negative consequences of battery deployment, what mitigation measures might be appropriate?

This work builds on a significant body of literature which finds that batteries can be invaluable in providing ancillary services to power systems; however, results of investigations into the ability of storage to substitute for network reinforcement, or to allow a lower-cost deferment, are mixed. Several authors report different behaviour from storage assets dedicated to maximising renewable penetration or lowering overall system operation costs, and engaging in "self-interested" wholesale trades.

In GB, batteries and other storage assets can engage in a range of activities. Short-duration batteries are very well-suited to provision of ancillary services such as frequency response services with fast (e.g. sub-second) response times. However, incomes from such services fell during 2022, as greater numbers of batteries entered frequency response services markets, and many batteries engage in other activities. Some engage in balancing services, though generally infrequently; some have a small but regular income from Capacity Market; income from DUoS and potentially TNUoS credits are an option in some locations, as are DSO flexibility services in some network constrained areas. Participation in wholesale trades is an option that became relatively attractive during 2022, and in which some batteries engaged. Academic literature and informal views from industry are agreed that batteries would normally need to engage in multiple activities to be financially viable. Unbundling rules class storage as "generation" and generally prohibit network operators from owning and operating batteries themselves, though DNOs, TOs and the ESO can contract with batteries for services.

This work simulates activities of self-interested batteries, intent on accruing maximum overall net revenues through wholesale trades. An agent model was created to simulate battery actions, under various rules governing trading decisions, using real wholesale price data, during three 5-week case study periods in 2022. The scenarios which accrued the greatest overall net revenues were selected for further study; in some cases variations to limit cycling, which may be desired to reduce battery degradation or comply with warranty conditions, were also investigated. This stage of work yielded plausible timeseries actions of batteries during the case studies. Timeseries of real grid-connected batteries were viewed, and examples of very similar behaviours were found, agreement considered strong enough to validate the battery simulation model.

Initially, this work explored the likely interactions between the simulated battery actions and wind generation, using the whole of Scotland as a case study area. In Scotland, maximum transmission flows are export-dominated and occur at times of high wind, during which curtailment of some windfarms is often necessary to comply with grid constraints, especially at the B6 transmission boundary between Scotland and England.

A study of the potential effect of batteries, if located in Scotland, would have on Transmission flows was performed, investigating the hypothesis, linked to Research Questions 1 and 2: "*a rational battery, engaged in wholesale trades, will not export at times of high wind energy availability in Scotland, nor will it add to network congestion*". The work found against the hypothesis: batteries engaged in trades, most days, whatever the wind conditions, as diurnal variations in wholesale price incentivised import and also exports. Any exports of a battery, sited in Scotland, at times of high wind would thus normally exacerbate transmission network congestion.

A further study was performed to investigate potential effects of batteries on distribution network flows, at six case study locations in southern Scotland, of which five had significant capacity of distributed wind connected on the same network. This study investigated the hypothesis, also linked to Research Questions 1 and 2: *"deployment of suitably-sized distribution-connected batteries, engaged in wholesale electricity trades, will not increase congestion on distribution networks servicing residential load demand and windfarms".* The outcome was that battery actions were likely to increase maximum export flows, as some exports were likely at times of high wind. Looking at the location with no wind generation, and others at times of minimal wind generation, the study found that at times, battery actions were also likely to exacerbate the maximum import flows, because the wholesale price pattern sometimes differed from that of the local demand flows, incentivising battery imports at times of high demand. Such events generally occurred around the middle of the day (outside of winter), during which, in other parts of GB, solar output is likely to be significant.

These findings, that actions of a self-interested battery engaged in wholesale trades, if located in Scotland, would be likely to exacerbate network congestion at times, are unfortunate for several parties: system and network operators, in having additional complexity to manage, but most of all for energy consumers, who must pay costs of additional balancing actions or network build which battery actions may cause, if misaligned with network needs. They may also prove detrimental to batteries themselves if the regulator decides to restrict their activities. Thus, some investigation into possible mitigation was conducted, exploring Research Question 4. The scenario of a battery connection with a "non-firm" or "flexible" connection, in which it may import or export only up to available network capacity at that time, was investigated. Such an arrangement is not uncommon for distribution-connected generators, especially windfarms in areas of high wind penetration. Battery actions were re-simulated, but with additional constraints of network thermal limits restricting battery actions at times. Overall net revenues were compared with base case of unrestricted network access, for a range of battery sizes. Assuming the battery would be curtailed without compensation, the costs of curtailment was calculated as the difference in overall net revenues between the "base case – no network restrictions" and "restricted network" cases.

In an attempt to harmonise an approach to battery sizing across all the six locations, all of which had differing amounts of spare network capacity, batteries were sized, and oversized, relative to available network headroom. Not surprisingly, curtailment costs were negligible for batteries sized up to the spare network capacity, and increased with increasing battery MW capacity, and broadly similar results were found across all locations. In most cases, batteries could be oversized compared to network spare capacity, by up to 10 – 20 MW, before any significant financial effect of curtailment was found (overall incomes at least ~ 95% of those under unrestricted network conditions). Projected curtailment costs in these battery size ranges are sensitive to network reliability assumptions, and more detailed study of abnormal network operating conditions is recommended. Battery oversizing with minimal cost of curtailment was seen over broader ranges of battery sizes for shorter duration batteries (2 hours, as opposed to 4 hours), and for most locations where a relatively even mixture of demand and generation was connected. Longer duration batteries (4 hours), and locations where flows were strongly either demand- or generation-dominated, generally had higher curtailment costs for a given battery oversize compared to network headroom. Curtailment has smaller effect on incomes for shorter duration batteries because they more often can complete their desired trades, even at lower power and requiring more time, before the electricity price changes and the trading action is no longer attractive.

Finally, this work investigates whether battery-triggered network reinforcement, or battery curtailment, might be the "lower overall cost" option at the six distribution case study locations studied above. The work identifies ranges of battery size for which battery curtailment would appear to be the "lower cost" option. Curtailment would be relatively attractive for shorter duration batteries, at locations with longer feeders where reinforcement would be more costly, where projected battery lifetime is short. This consideration is complicated by several considerations. First, curtailment and reinforcement costs are borne by different parties. Second, limitations of access to up-to-date data on reinforcement costs, and indeed, wholesale price data on which the simulations are based, necessitate some caution in viewing these results, though generic patterns of results are expected to be robust. Third, different results would be obtained if the calculation was "reinforce now or reinforce later" as opposed to the "reinforce or not" case investigated. There were insufficient data available to explore the former question, though it is expected to be relevant in many areas where reinforcements will be needed soon in any case. The work also considers the apportionment of connection charges between a developer and DNO, and to what extent current arrangements encourage a "lowest overall cost approach". This work raises broader questions: whether seeking "lowest overall costs" based on a narrow comparison of battery curtailment and reinforcement costs is even the most pertinent consideration, given that both network reinforcement, and also addition of batteries, could potentially provide wider value for other connecting customers, and for network operability. The work concludes by answering the research questions posed, suggesting further work, and with some recommendations for policy makers.

The main takeaway for policy-makers and planners from this work is as follows: while deployment of sufficient flexible assets is going to be essential to aid GB's electricity system transition, their deployment ***does not*** in itself guarantee their use to that end. Suitable accompanying rules and incentives are necessary to ensure flexible assets benefit the wider electricity system: without such rules or incentives, flexible assets can be expected to add to existing network challenges, at times and in places, as well as easing such challenges at other times and places. At time of writing (summer 2025), development of more suitable rules and incentives is needed.

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1. Chapter 1 Introduction

1.1. Background and motivation

1.1.1. Great Britain's electricity system at the start of this thesis

This work is set in the electrical power system of Great Britain (GB), the location of study. This thesis is undertaken at a time of great change in this electricity system, and the UK's wider economy.

At the 1992 United Nations (UN) Earth Summit in Rio, the United Nations Framework Convention on Climate Change (UNFCC) was set up, with agreements stabilise greenhouse gas (GHG) emissions [1]. Building on this Convention, industrialised nations agreed programmes of GHG emissions reductions, over forthcoming decades, at the 1997 Kyoto summit, and limits on global temperature rises were agreed in Paris in 2015 [2], [3]. The UK passed the Climate Change Act 2008 [4] to codify its commitment to these international agreements. This Act bound the UK to reduce its territorial GHG emissions by 80% of 1990 levels by 2050, together with intermediate carbon budgets at earlier dates. These commitments were later strengthened, in 2019, to "Net Zero" UK territorial GHG emissions by 2050, following advice from UK Government's Climate Change Committee, the CCC [5]–[7].

The UK introduced several policy instruments to facilitate the decarbonisation of Great Britain (GB)'s electricity system. From 2002, the Renewables Obligation (RO) [8] encouraged the development of renewables, initially predominantly windfarms, with some solar PV installations participating from 2012 [9]. Small[1] renewable generators, many of them solar PV, have been supported by the Feed-in Tariff (FiT) [10] scheme from 2010. Also in 2010, the "Connect and Manage" scheme [11] was introduced to support new renewable generators connecting to a location with insufficient electricity transmission network capacity. Though the RO and FiT schemes closed to new entrants in 2017 and 2019, respectively, support for some renewable and other low-carbon projects continued via the Contracts for Difference scheme, launched in 2014, introduced as part of the UK's Electricity Market Reform package, together with a Capacity Market to protect the electricity system against generation inadequacy [12]–[15]. By the end of 2022, the year this thesis investigates in detail, the GB grid had over 27 GW of connected wind (combined onshore and offshore) and approaching 15

[1] Capacity up to 5 MWe

GW of solar generation [16], significant penetrations on a power system with maximum system demands of around 50 GW [17].

National Grid ESO set its own target of "zero system operation" by 2025, in 2019 [18], meaning that the ESO would not constrain on additional carbon-emitting generation for system operation.

In 2021, the UK Government pledged to "fully decarbonise" the electricity system by 2035 [19]. In late 2024, a new UK Government committed to "Clean Power 2030", bringing forward the date for power system decarbonisation to 2030 [20], though using an amended definition of "*clean power*": at least 95% of electricity generation is to be from "clean" sources, i.e. renewables and nuclear. It is expected that some unabated gas generation will be needed at times of low renewables outputs, but such generation will account for no more than 5% of total electricity generation[2] [21], [22].

Among the many challenges of operating an electricity system, necessarily with more inflexible generation sources, such as wind, solar and nuclear, is *flexibility.* The UK Government and the energy regulator Ofgem wrote *"To keep the power system stable, supply and demand have to balance in real time. Flexibility refers to the ability to modify generation and / or consumption patterns in reaction to an external signal (such as a change in price, or a message)"* [23].

Another challenge is network limits: new sources of generation are often sited at different locations to traditional power stations. The former challenge is an example of potential *temporal* mismatch between generation availability and demand; the latter of *locational* mismatch, where there is insufficient network capacity to transport electricity from generation to demand centres at all times. The causes and management of the above mismatches are summarised in Table 1.

Will deployment of sources of *flexibility* facilitate the decarbonisation of the electricity system, by potentially relieving both temporal and locational constraints?

[2] The pledge also is for 100% of GB's electricity *demand* to be met from "clean" sources, in the expectation that GB will export electricity at times of high renewable output and low demands [22].

Table 1 Summary of mismatches between generation and demand

	Place	Time
Why might / do mismatches occur?	• Not feasible to locate generation at every site which consumes electricity. • Economies of scale in building larger generators of some technologies. • Locational constraints in siting of some generators.	• Mismatch between times of generators' outputs and of energy consumption patterns .
Existing solutions: current providers	• Distribution networks, Transmission networks, Interconnectors.	• Schedulable generators with a fuel store (primarily gas, previously coal).
Mechanism for avoidance / management of mismatches	• Left "to the market" for generators to decide where to locate. • Some signals on location via generator TNUoS tariffs (for TG) and connection charges (for DG).	• Wholesale prices (over half-hourly Settlement Periods), and potentially imbalance prices. • ESO Balancing Actions. • Some signals from DUoS tariffs (for DG and demands – subject to tariffs). • In some locations, weak TNUoS signals (for large demands and DG). • Capacity Market for times of generation inadequacy.
Why are mismatches becoming greater problem with decarbonisation & new technologies?	• Significant constraints on location of many renewables. • Mass availability of smaller renewable generators of (largely wind and PV) connecting to Distribution Networks.	• Inflexibility of many low-carbon generators: ○ Weather-dependent renewables – output only when weather is suitable / during daylight / following rain ○ Nuclear stations – constant output (current GB fleet).
New & proposed solutions: providers & mechanisms	• Flexible / schedulable generators and demands, including storage providers. • Network reinforcement: Transmission and / or Distribution (and additional interconnectors). • Additional / greater volumes of flexibility / balancing services. • Market mechanisms considered under REMA[3] [24].	

[3] Review of Electricity Market Arrangements, undertaken by the UK Government

1.1.2. Flexibility: definition, types, aims, and sources?

Flexibility can involve a shift in electrical demand or generation: in time, or potentially, in location.

Temporal flexibility

The electricity system requires that generation and demands are exactly in balance on a second-by-second basis. The GB power system was powered largely by fossil fuel and other despatchable power stations, stations which could "flex" their outputs up and down according to patterns of demands, over timescales of minutes to hours, and with their fuel stocks allowing planning and scheduling over days, weeks and months. A decarbonised system will have far fewer such stations. Many larger renewable generators can and do respond to ESO instructions to reduce output, within seconds or minutes, but it is normally uneconomic to run them in conditions in which they could increase output. Furthermore, such generators cannot deliver at times of low resource, such as low wind, prolonged dry weather, or at night.

The current fleet of UK nuclear power stations operates at constant output, by design, providing "baseload" to the GB electricity system [25]. Some nuclear stations of different designs can provide a degree of flexibility in output, in response to varying demands or outputs from renewable generation, as is common practice in the French nuclear fleet[4] [26]. However, such operation would be very unattractive for a private nuclear station owner, primarily because of reduced income from electricity sales, with no reduction in operational costs [26], as the bulk of the costs are in the station construction. Unlike the turning down of wind generators, "core ramping" of nuclear stations requires significant planning, and is further limited towards the end of a fuel cycle [27]. Furthermore, temperature cycling associated with varying core temperature and station output would tend to shorten the lifetime of the reactor and / or fuel[5], entailing further economic cost [25], [26]. Some in the industry suggest a future fleet of Small Modular Nuclear Reactors, if built, could operate more flexibly [28]. However, the main avenue under consideration to achieve a more flexible future fleet of nuclear power stations, large or small, is the diversion of their output heat or electricity into another application, such as a nearby industrial process, energy storage facility, or an energy-demanding activity such as hydrogen electrolysis or seawater desalination, at times of low

[4] Reductions in output are achieved by "core ramping", partial insertion of "grey" boron control rods, to reduce the rate of fission and thus thermal output [26].

[5] Core ramping with control rods can also lead to the build-up of undesirable isotopes in the reactor, potentially limiting ongoing ramp rates [26].

demand from the electricity system [25], [28]. In essence, any flexibility of future nuclear stations will probably be most economically provided by co-located energy demands, rather than the stations themselves.

Thus, other sources of flexibility, i.e. the ability to increase or decrease generation or consumption, are needed. Furthermore, with increased penetration of inverter-connected generation – which encompasses most renewables - reduced system inertia has increased the speed at which some system services need to be delivered [29].

A greater degree of temporal flexibility of electricity system users could allow greatest use of low-cost and low-carbon generation, when it is available, and reduce the total capacity of generation needed to provide adequate security of supply at times of low renewable output.

Spatial

The existence of a National Grid allows users of electricity to access outputs from generators near and far, which enables very high levels of security of supply, and access to some of the lowest-cost generation available (subsidies to some technologies and generators notwithstanding). However, such a system comes at a cost of building and maintaining Distribution and Transmission network infrastructure, with the GB system's 9 interconnectors enabling further electricity transport between countries.

With an increasing proportion of generation being built at the extremities of the electricity system, particularly wind in Scotland and offshore, then additional transmission grid is needed to bring such electricity to market. Smaller generators, especially solar PV and smaller wind generators, connect to Distribution networks that were not designed for such use, and which in many areas lack capacity for desired connections.

A greater degree of flexibility in location of some electricity system users could reduce the capacity of additional grid to be built in some places, allow deferment of some network reinforcements.

1.2. Research questions

This thesis seeks to explore the value of flexibility to the GB electricity network: it is expected that at least some of these findings will be relevant to other power systems, on a similar decarbonisation journey, and with similar characteristics of regulation and generation mix.

1.2.1. Overarching research question

Will installing, deploying and enabling suitable types and capacities of "flexibility" enable "decarbonisation at lowest cost"?

UK Government's and Ofgem's report "*Upgrading our energy system. Smart systems and flexibility plan*"[30] in July 2017, following a Call for Evidence on a smart flexible energy system the previous year [23]. The 2017 report stated the need for "a more flexible energy future", in the light of new technologies, more low-carbon generation, and more distributed resources. The consultation authors stated such flexibility would bring significant benefits for consumers, the system and the wider economy.

Deployment or installation of sources of "flexibility" are estimated to be able to save significant expenditure - £17-40 billion from 2017 to 2050 - for the GB electricity system as a whole, according to UK Government- and Ofgem-commissioned work by the Carbon Trust and Imperial College [31]. Projected savings would arise mainly from avoided OPEX – fuel and carbon costs – and avoided CAPEX from avoided capacity of generation and avoided distribution network reinforcement. The work found that deployment of flexibility would incur CAPEX costs of implementing "Demand-side response" and storage solutions, but that those costs would be outweighed by overall cost savings.

Other GB-specific reports on the benefits of flexibility include Ofgem's 2015 position paper [32] and a report by trade associations Energy UK, the Association for Decentralised Energy, and BEAMA [33]. Academic sources citing the value of flexibility to electricity networks in general include [34], [35].

This overarching research question is too big for a single PhD, so this work focuses on some subsets of this question: storage, one very clear source of flexibility: short duration batteries. This type of technology is selected with the following justifications:

- Short duration batteries are, in principle, ideally suited to addressing problems of *temporal mismatch* between generation and demand, as highlighted in Table 1. Energy storage, by definition, can be regarded as a way of "moving energy in time".
- Batteries, along with other types of energy storage, can act as both schedulable generators and also as schedulable demands. Thus, the study of storage assets could also give insight into possible behaviour of other types of flexible generators or demands, and their potential impacts on the wider electricity system.

- Short duration batteries are currently highly relevant. With deployment of batteries increasing from around zero in 2016 to over 3 GW by 2023 [36], and over 80 GW of proposed battery projects agreed by network owners [37]–[43], a better understanding of their likely impacts on the GB electricity system is important. The majority of these GB-deployed batteries are *lithium-based* and operate for *short duration*, i.e. having the ability to operate at full power for no more than 4 hours [44], a finding which the IEA reports is also occurring worldwide[6] [45].
- While clearly batteries and other storage assets cannot address the *locational* mismatch between generation and demands, relief of temporal mismatch could potentially reduce the capacity of networks (distribution, transmission and interconnectors) needed to address such locational mismatches. (This matter discussed in Chapter 2).
- Batteries also have the advantage that they can be built in locations country-wide, unlike some other storage technologies, such as pumped hydro storage (PHS), the only other type of electricity system storage currently operational at scale in GB[7], which requires suitable geography.

Even narrowing of scope to short-duration batteries is too wide a field, as batteries can deliver on a wide range of ancillary services and to engage in other activities, both as stand-alone and behind-the meter or co-located with generators, all of which can effect on multiple aspects of system operation and behaviour. Thus, the scope of this study is to concentrate on *network congestion,* at both transmission and distribution level, as technology developments, falling costs, and the need to decarbonise have increased the challenges of mismatches between generation and demands in both time and space. Figure 1 illustrates schematically where this question fits within wider matter of flexibility on the GB electrical power network.

[6] The IEA report [45] also states that though flow batteries operating for longer timescales "*could emerge as a breakthrough technology for stationary storage*"

[7] Other than energy stores using other energy vectors, such as storage facilities for natural gas

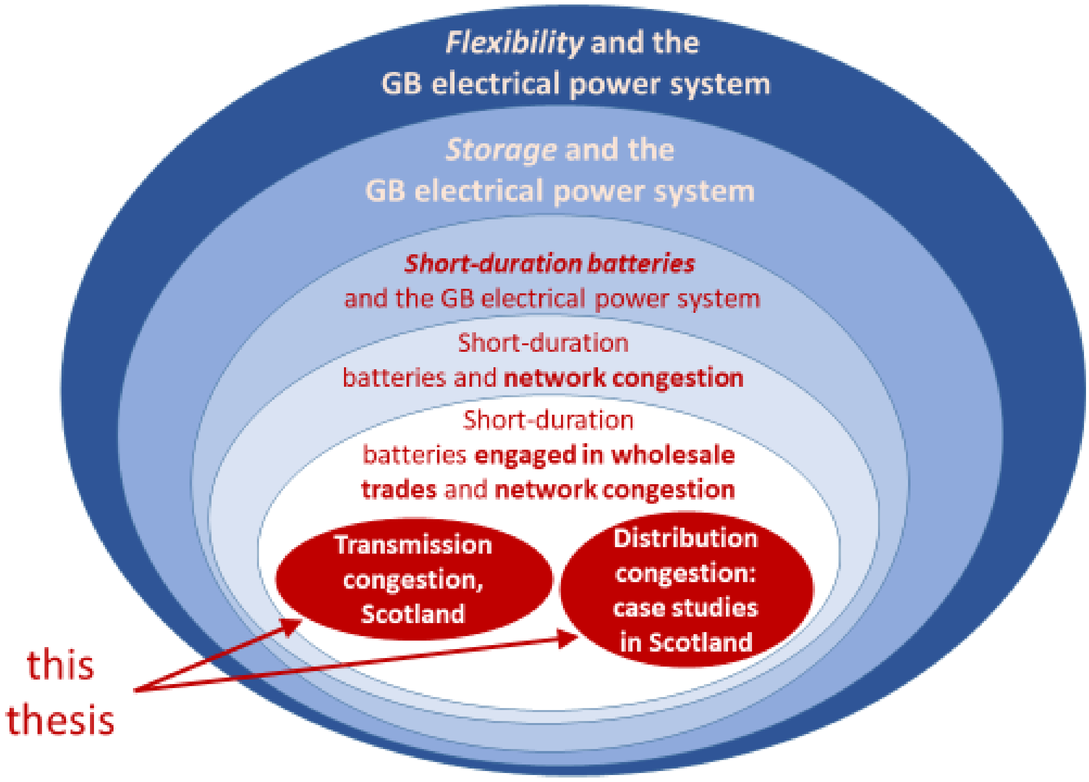


Figure 1 Scope of study of this thesis

1.2.2. Research questions and thesis overview

Following the narrowing of the scope of main study, this thesis considers several questions:

Q1: What kinds of behaviours are foreseeable from short duration batteries?

Q2: Are expected behaviours of short-duration batteries likely to alleviate or exacerbate network congestion and system needs?

Q3: Is a large-scale roll-out of batteries likely to facilitate or obstruct deployment of renewable / low carbon generation, and the electricity system's transition to Net Zero?

Q4: If there are any negative consequences of battery deployment, what mitigation measures might be appropriate?

In Q1 and Q2, the term "behaviours" means the magnitudes, durations, timings and frequencies of energy flows from the network to the battery – termed "imports", and energy flows from the battery to the network, termed "exports". "Behaviours" also refers to the presence or absence of any recurring patterns in these energy imports and exports, and circumstances in which these energy flows occur.

In Q2, the term "*expected* behaviours" means examples of *credible* actions which an *economically rational battery, in GB,* could feasibly undertake. In GB, batteries are generally privately owned, rather than owned by network owners or the system operator, a distinction further explored in the following chapters. Being in private ownership, this thesis assumes the battery owners will take *economically rational* decisions, in order to seek to maximise revenue from available activities and markets. The term *"economically rational battery"* also assumes that batteries *can* engage in the most profitable actions available, and their actions are not limited by lack of access to information (e.g. prices of services or wholesale prices), any barriers to liquidity in markets they may wish to engage in, or any operational or other reasons that may limit their activities, for example to preserve asset health or comply with warranty conditions.

These research questions can be summarised more informally as:

"*What would a battery (in GB) do, how would it affect electricity networks, and is any further action needed to achieve overall system benefit?*"

In this thesis, Chapter 2 reviews literature on how storage assets can provide system services, and the extent to which they might reduce the need for network reinforcement.

Some of the main options for short-duration batteries to engage in financially viable activities are discussed in Chapter 3.

Chapter 4 describes the methodology for simulating the overall net revenue a battery may accrue from engaging in wholesale trades that is used in this thesis.

Chapters 5 and 6 use this battery simulation method to investigate Q2 and Q3. Chapter 5 investigates the effect of likely battery behaviour on transmission network congestion between Scotland, and England and Wales. Chapter 6 is a similar study, using selected case study locations on distribution networks, in southern Scotland.

Chapters 7 and 8 use a variant of the battery simulation to investigate Q4. Chapter 7 investigates one possible approach for Q4: the question on mitigation for any negative consequences of battery deployment. This chapter investigates the financial effect for the battery owner of its connection with a non-firm connection, in which battery imports and exports are limited to available network capacity at the time. This chapter seeks to understand whether such an arrangement could be financially viable for a battery owner.

Building on the work of Chapter 7, Chapter 8 investigates how costs of battery curtailment, in a "non-firm" connection scenario, would compare with costs of network reinforcement, at the same case study locations as investigated previously. This chapter discusses where and for what range of battery sizes curtailment of batteries would be a lower-cost solution than a battery-triggered network reinforcement, while acknowledging that different costs are borne by different parties.

Chapter 9 concludes this thesis.

This thesis is set entirely within the power system of Great Britain. However, many of the findings are likely to be relevant to other unbundled electrical power systems with high penetrations of weather-dependent renewables (especially with significant wind) at a similar point in the journey to decarbonisation.

1.3. Contributions

1.3.1. Contributions directly associated with this work

The following two conference papers arose from this thesis

- S. Brush, G. Hawker, and K. Bell, 'Batteries in wind-dominated areas of network: solution or problem? A Scottish case study', in *Renewable Power Generation and Future Power Systems Conference 2023 (RPG 2023 UK)*, 2023, vol. 2023, pp. 144–149 [46]
- Susan Brush, Graeme Hawker, and Keith Bell, 'Impact of batteries' energy trading on distribution network congestion: a Great Britain case study', in *59th International Universities Power Engineering Conference (UPEC)*, 2024 [47]

Both of these papers were peer reviewed. The peer review process resulted in significant amendment of the second of these papers.

1.3.2. Other contributions

During this work, Susan authored / co-authored the following reports:

- UKERC response to JCNSSI Inquiry: Critical national infrastructure and climate adaptation [48]

- *Operating a Zero Carbon GB Power System in 2025: Frequency and Fault Current* [49], of which Susan was first author of the sub-report "*Market Needs*" [50]
- *Energy Technologies for Net Zero. An IET Guide*. [51]

Out of the latter work arose a journal paper, to which Susan contributed:

- *Which way to net zero? A comparative analysis of seven UK 2050 decarbonisation pathways* [52]

These earlier works provided valuable background knowledge on which to base the research of this thesis.

2. Chapter 2 Overview of reported effects of storage on electrical networks' operation and reinforcement needs

Chapter summary

This chapter seeks to summarise the current understanding of the effects, in different jurisdictions and conditions, that batteries and other types of storage can have on electrical networks, with a particular focus on the ability of storage to defer or avoid the need for network reinforcement. This is important background knowledge on which to base work to address the research questions posed in the previous chapter.

Batteries and other types of storage assets have many characteristics which can enable them to provide a variety of services to electrical power systems, over timeframes ranging from sub-cycle to months and years. Many such services will be needed in decarbonising electricity systems to help manage inherent variability of weather-dependent renewable resources, as well as to provide some essential ancillary services.

There is a great deal of research interest in the value that energy storage systems can bring to electricity systems, on scales ranging from a couple of kW and kWh to large transmission-scale facilities. Greatest system cost savings are generally achieved through increased penetration of low-marginal cost renewable energy which allows reduced use of expensive and environmentally-damaging fossil fuelled power generation, and, in a low carbon future, use of expensive fuels and / or CCS. Storage could also contribute to system adequacy, thus reducing the necessary installed capacity of despatchable plant. However there is also potential for storage to reduce or defer network reinforcements, and to enable greater use of more distant renewables, which in some cases is found to be financially beneficial. A number of results, and real experience in one network jurisdiction, find battery energy storage complements solar PV generation very effectively; however other studies found batteries a have more limited effect in reducing curtailment of wind generation because of mismatches in the duration of short-duration batteries currently deployed, and common durations of high wind events. Section 2.2 summarises literature with the common assumption that storage would be owned by, or despatched for, the benefit of the network or system operator; many studies disregard inherent uncertainties in modelling energy generation and demands. In contrast, section 2.3 describes several studies which find that storage assets operate differently when dedicated to system benefit, than if they were to maximise their own incomes through arbitrage, or enable lowest cost or best value for co-owned on-site renewable generation and / or demand. Finally, the GB regulators have recently changed their approaches in how storage assets would be modelled, in attempt to facilitate faster connections. The question of "*what would a battery do, and how would it affect electricity networks?*" if connected in Britain, is not adequately answered in the preceding literature, and is the subject of this thesis.

2.1. Overview of storage activity in electrical networks

Though the scope of this PhD is *short-duration batteries*, it is useful to review these and their effects on electricity networks in the context of the broader topic of services which energy storage assets in general can provide to grids.

Many authors describe energy storage as an enabler for greater roll-out of renewable energy into electrical power systems, and also to support more active distribution networks. Reviewing storage technologies including mechanical, electromagnetic, electrochemical, gravitational and synthetic fuels (e.g. hydrogen), [53]–[58] describe various roles storage devices can have for electrical power systems, of which [54], [56], [58], [59] refer to a UK or GB context.

Storage devices can provide services at timescales ranging from milliseconds (within a cycle of the electrical waveform) to support power quality, potentially up to weeks or longer for seasonal energy storage[8], and can support power system operation and its users under both normal and contingency conditions. These uses are summarised below in Figure 2.

[8] [56] stated at time of writing (2015) that in the absence of commercialised energy storage technologies for seasonal storage timescales "storing fossil fuels is still a practical solution".

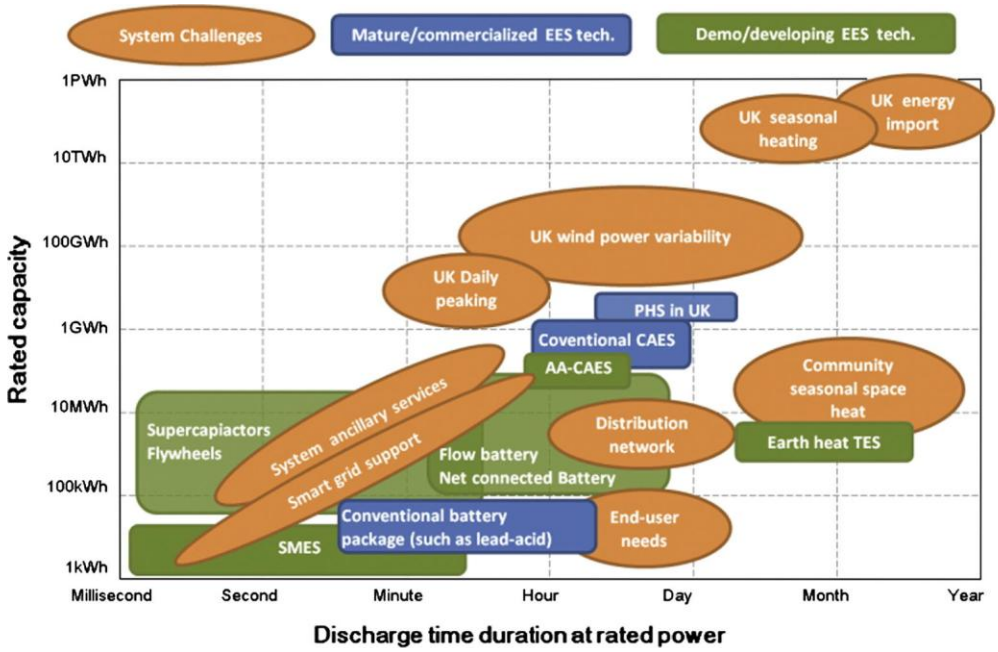


Figure 2 Electrical energy storage technologies with challenges to the UK energy systems. Reproduced from [56]

All reviews describe storage deployment as an enabler for greater integration of variable-output renewable generation, by offering services traditionally provided by conventional fossil-fuel plant, and by mitigating some of the challenges of variable renewable generation to grids and system operators. [53], [57] also refer to creation of a peak-output profile suitable for demand from inflexible baseload (nuclear) stations.

Applications for storage in the minutes to hours timeframe include "time-shifting", "load-levelling", "peak-shaving", performed by batteries, pumped hydro and compressed air energy storage devices, with potential for also flow batteries and thermal energy storage to provide such functions. Interestingly, [54], [55], [58] refer to energy arbitrage (wholesale trades) as a service that storage devices could offer, a topic area which is revisited in more detail in the following chapters of this thesis.

Particularly relevant to this study are applications of storage to reduce congestion on electrical power networks, and the need for their reinforcement. [53]–[56] refer to *relief of transmission congestion* and / or *deferral of transmission network upgrade* as a service, with [55] also listing distribution network deferral as a benefit storage can bring to networks. [58] refers generally to "*network upgrade investment deferral or avoidance*", including "*local network constraint management services*" as a potential benefit, and is described in greater detail in Section 2.3.3. The following sections of this chapter review literature on the specific question of whether storage deployment can reduce system costs by avoiding or deferring the need to reinforce electricity networks, particularly in the context of energy transition requiring additional renewables.

In some ways, the division of services which storage assets could provide is a little artificial, in that several are different ways of viewing the same matter. For example, a storage asset successfully performing a "*peak shaving*" type of role may, in so doing, may provide *congestion relief* to the network, and so may *avoid the need for a network reinforcement* there. In the case of inflexible generation (solar PV and wind) causing generation-driven peaks which do not coincide with local demands, any "*generation peak shaving*" service a storage asset could provide would be likely to *enable greater use of the renewable resource*, with financial benefits to the generator owner, and it is likely, financial and environmental benefits to the wider system and all users, by reduced reliance on conventional generators. Enlarged demand peaks may arise from the *electrification of heat and / or transport*, so any successful storage deployment to address such increased demand flows could enable greater penetration of demand electrification technologies. Furthermore, where peak network flows are demand-driven, and rise above the network's secure (e.g. 'N-1') capacity, then a deterioration in *reliability of supply* would be expected, a problem which, again, a storage asset may alleviate.

Even understanding that these different network services do overlap with each other, the sections below utilise the different named network services, according to the emphases of the studies. The chapter below also separates reviews assuming "perfect foresight, storage dedicated to serving the electricity system" from more "real world" scenarios, in which storage assets may have different motivations and thus exhibit different behaviour.

2.2. Storage dedicated to serving the electricity system

The papers in this section assume that a storage asset would be deployed in order to assist the electricity network or wider system, such as by relieving network constraints. Most of these papers state or imply that the storage assets' scheduling would be controlled by a network or system operator; a smaller number e.g. [60], [61] raise the possibility of third party ownership, but within a scenario in which the battery is under contract to deliver specific services, or that the battery owners agree for the battery to be remotely controlled, e.g. by a DNO. There is a short discussion on methodologies following the individual paper reviews, in subsection 2.2.4.

This section splits reviews by the *scale* of proposed battery (or other storage) projects. Section 2.2.1 describes smaller scale storage projects connected to lower voltage levels of distribution networks; Section 2.2.2 considers larger projects, of a scale to be connected to or to serve higher voltage levels of distribution networks and transmission networks. This distinction is made because of some generic differences in technologies (potentially both generation and storage), and in potential services or benefits the storage assets could deliver.

2.2.1. Small scale storage: LV / MV / HV networks

This section describes *smaller scale* projects, of a scale to be located within homes, small commercial demand user sites, or grid-scale batteries of a scale to support lower-voltage levels of distribution networks (LV and HV in GB system, up to a nominal voltage of 22 kV [62] , there being no "MV" voltage level). Power flows can be more stochastic at the lowest voltage levels of network, there being fewer connected customers, and thus less of the diversification which tends to "smooth out" variability in flows over time and from place to place. Thus, arguably, the lowest voltage networks are the most challenging to manage [63]. In all cases, the storage assets are batteries.

2.2.1.1. Reduction of maximum network flows: peak shaving, time shifting and / or load levelling

A number of studies investigate the effect of small batteries, for use in residential properties, or to support LV or MV networks, using storage for a few hours a day for peak shaving at times of maximum demands, or potentially maximum PV generation. The studies used generic or actual load profiles, and calculate storage sized to avoid thermal overloads or voltage violations. These services could alternatively be viewed as "congestion relief" or "avoidance of network reinforcement".

Pimm et al [64] in 2018 investigate the potential for batteries in homes to perform peak shaving for LV distribution networks, using typical houses in Birmingham, England, as case studies, using the CREST model [65] to simulate residential demands. The authors state potential system benefits and cost reductions of peak shaving arising from reduced peak generation capacity and associated peak plant emissions, and deferred distribution reinforcement, particularly with expected future load growth from electrified transport and heating. The work found that 2kWh of battery storage per house could reduce solar PV export peak flows at LV substations by 50%, and that 3kWh per household could keep demand peaks to current levels following electrification of space and water heating with heat pumps. The study concludes that batteries sited in homes could significantly reduce peak flows on LV networks and substations and potentially also at higher voltage levels, if batteries are suitably incentivised or coordinated to do so. The authors acknowledge that such incentives or coordination mechanisms did not exist at the time of writing.

In a piece of work on a distribution network in NW England in 2018, [66], Johnson, Mayfield and Beck also explore the use of distributed battery storage to avoid LV reinforcements, in a context of outputs from rooftop PV causing voltage rises, potentially in violation of network limits. A central coordinator uses a linear programming OPF to control battery energy storage units located "behind the meter" of residential properties, seeking to minimise consumer bills through use of on-site solar PV, low-price "economy 7" night time tariffs. The algorithms include constraints of ranges of voltage, power flows, power factor and line losses within the feeders, and takes into account expected battery degradation rates; a conservative estimation of PV output was used to allow for uncertainty in weather forecasts. "*Best-case*" locations and sizes of batteries were computed, using a multi-period mixed integer linear programming approach, aiming to minimise the cost of installation of batteries and inverters, costs which were later compared with traditional network reinforcements. The study presumes the batteries are either owned and operated by the DNO, or by a third party on behalf of the DNO. However, the work found that in all studied cases, traditional reinforcements could be carried out at lower cost than installation and operation of battery energy storage, even allowing for the benefit of reduced residential electricity bills. The authors suggest, however, that other scenarios, including longer feeders in rural areas, and deployment of air-source heat pumps, would be worth further study, both scenarios being more prone to voltage violations than the scenarios studied, to see whether battery deployment may be a more cost-effective solution than network reinforcement in these other cases. Presumably a significant fall in capital costs of battery storage would also cause deployment of batteries to be more financially favourable.

In [67], Samper Vargas and Flores study a real congested section of MV / LV distribution network in Argentina, with high penetration of rooftop solar PV, and in which projected increases in both demand and solar PV export flows were expected to exceed network limits in the coming years. Taking into account costs of network constraints limiting generation and demands at times of peak flows (costs of energy not served, curtailed PV generation and voltage violations in excess of 0.05 per unit), the work compares costs of "no action", "traditional reinforcement" and "battery storage", after both five and ten years. Assuming annual demand growth of 4%, the study found that cost of losses would escalate over the coming decade under a “no action” scenario, and that traditional reinforcements (of a transformer at year 2, and two lines at years 3 and 4) were less costly than “no action”. Regarding storage as an alternative to reinforcement, the authors considered several types of battery, selected lead-acid, and proposed battery installation at seven selected sites as an alternative to the transformer upgrade and reinforcements of two lines. Net Present Value (NPV) of costs after 5 years were slightly better than those of traditional reinforcement, and projected NPVs of the two alternative interventions after ten years were the same. A further scenario of initial installation of batteries, and later reinforcements (all in year 6), yielded the best financial results, even with sensitivities of differing rates of demand increase. However, this result was sensitive to major increases in costs of batteries – increases up to 50% were considered - potentially arising from future Argentinian currency devaluation. The major difference of this piece of work from a UK situation is indeed the financial environment: this study used an annual financial discount rate of 15%; in the UK, the Weighted Average Cost of Capital for distribution network companies was just under 4% p.a. during the ED2 price control period [68]. Thus, deferral of reinforcement here in Britain would have a much smaller financial benefit than in Argentina.

Fidalgo, Couto and Fournié describe a study of an active distribution network, initially in a single line test model, based on a mainline and substation in Vila Robin, in Portugal, and later in a model of a medium voltage network based on part of the city of Bologna, Italy, in [69]. The simulated networks had “no smart grid” modes, with no flexible resources, and “smart grid” modes, with connected microgeneration, flexible demands, EV “smart charging”; initial plans to also include energy storage were not pursued, though the use of other flexible resources makes this paper relevant. The modelling was over a 20 year period, and assumed growths in loads which would approach or pass the maximum loading of network components e.g. cables, at some point. The authors describe the context: the network rules oblige the network owner to upgrade an asset once peak flows reach around 90% of an asset’s rated capacity, a situation the authors refer to as “triggering reinforcement”. The authors investigated whether the flexible resources could be used to avoid or delay a “triggered” reinforcement, and whether such actions would save money: however they found, in contrast to other studies, that deferral of network reinforcement was not the overall lowest cost option. Their analyses included costs of energy losses, costs which were significant and which were reduced following reinforcement, alongside costs of energy, and in the “smart grid” scenarios, costs of shifting demand and EV "smart charging". In both test networks, the authors found that an "optimal upgrade", conducted earlier than a "traditional upgrade" allowed lower overall costs, in both "smart grid" and "no smart grid" scenarios. The effect of "smart grid" compared to "no smart grid" scenarios were variable.

A Spanish study into the potential for batteries to avoid or defer MV distribution network reinforcement, by "peak shaving" is presented by Mateo et al (2016) in [70]. Using reference network models, with input parameters corresponding to rural and urban areas, the research models the network, using standard load and generation profiles. In the "added storage" case, the battery is despatched to discharge at times of peak demand, and to charge at times of lowest demands. This scenario is costed and compared with an alternative scenario of network reinforcement. The work found that at current costs of batteries, network reinforcement would be a lower-cost action, but that future falls in battery prices, or extensions in their service lives, could make storage more attractive. The same team conducted a later study, [71], again assuming batteries are operated by or for the benefit of the DNO to reduce voltage or thermal violations, at a 500-bus piece of network with expected load growth. The study uses a genetic algorithm to compare different battery storage alternatives, and DNO must choose a reinforcement decision in the event of violations. The work found some cases where battery storage was an economical alternative to network reinforcement, but generally traditional reinforcement was a lower cost option. They stated the economics for battery installation may be more favourable to batteries if they are allowed to engage in other revenue streams.

In [72], Brubæk and Korpås study a small remote Norwegian section of distribution network which supplies cabins used for holidays, and in which voltage violations at times of highest demands would require network reinforcement or another solution. The study used a backward-forward sweep algorithm to study load flows and to compare line reinforcement with an proposed alternative of battery installation. The work found that either reinforcement or installation of a suitably-sized battery could address the voltage problem. In the main case study, line reinforcement would be 77% cheaper than a battery solution, though the battery would be the cheaper option under some sensitivities requiring smaller battery: a shorter line causing lower voltage drops, or reduced peak load because of connection to a smaller number of cabins. The battery model here uses only voltage to trigger instructions to charge or discharge, and has a surprisingly high round-trip efficiency of 95%; the battery sizing requirements require 10kW and 65 kWh, which is a longer duration than is usual for lithium ion batteries. The study neglects battery degradation or potential effects of temperature on its performance, and suggests many areas for further work. Though a fairly small study, its findings are in line with others'.

Nykamp et al describe the potential for battery storage to perform a "peak shaving" role in an area of the town Westnetz, Germany, for a limited period of time, in [73]. Peak flows in part of the town's network sometimes breach network limits, which would normally trigger a reinforcement. However, wider reinforcement work was planned in Westnetz, which would leave any local reinforcement as a stranded asset. The study suggests that a temporary battery unit could be used for a year to control network flows and avoid violations, pending wider reinforcement, after which the battery could be relocated. The paper states DNOs are incentivised to reduce OPEX expenses, which a third party flexibility service would be, and that classification of the battery as a CAPEX grid investment may be more attractive option to the DNO. However, electricity system unbundling regulations would prohibit a DNO-owned battery from engaging in other activities such as balancing services, though such activities may be an overall best use of the asset. Overall, this paper is an interesting case of potential battery use as an alternative to a short-term reinforcement, and some of the relevant regulatory factors.

These papers, describing studies in GB, several other European countries and one from South America, give examples of situations where installation of a suitably controlled or incentivised battery can reduce projected rises in maximum power flows in distribution networks. In all cases, whether peak flows were caused by increases in demands or PV generation, battery installation could avoid or delay network reinforcement, though the findings regarding financial competitiveness of a battery installation, compared to traditional reinforcement, were very mixed. Factors favouring battery installation to be lower cost include a lower capital cost of battery and a higher cost of network reinforcement; a higher financial discount rate also favours deferral of network reinforcement. The scope of the study is also important, for example, few studies include the cost of energy losses, which would strengthen the case for reinforcement, and some circumstances, such as a temporary need for increased network capacity, would tend to favour temporary battery deployment.

2.2.1.2. Enabling electrification of heat and transport

Most decarbonisation pathways for the UK require significant electrification of heating and transport, to reduce these sectors' current dependence on fossil fuels [52]. This section describes how the use of batteries could help enable existing distribution networks cope with the additional demands that these sectoral shifts are expected bring.

Mohamed et al studied a 53-node distribution feeder in Northern Ireland, in which a simulated uptake of heat pumps and EVs was projected to cause voltage violations during evenings [74]. The researchers use several swarm-inspired optimisation algorithms to compute suitable sizing and siting of battery energy storage. The modelled network behaviour with storage avoided violations, and is a suggested tool for network planners, to prepare for an expected take-up of Low Carbon Technologies, and the demands it is likely to place on distribution networks.

Steinbach and Blaschke [61] examined the potential for home-located batteries, together with PV systems, to support Germany's distribution network in the face of increased demands from electrification of transport. Studying rural, suburban and urban case study sections of network, flows were simulated using load profile data supplemented by calculated PV, EV charging, and battery flows, where the batteries are instructed to charge whenever PV generation exceeds consumption, and to discharge whenever consumption exceeds PV generation, whenever the battery's State of Charge allows. The work found such battery and PV action would reduce distribution peak flows and allow greater EV penetration before additional loads would trigger reinforcement, and recommends government action to facilitate household PV and battery installation.

Also in Germany, Held et al [75] investigate the use of battery as a temporary measure to avoid feeder overloads, caused by EV-charging, pending network reinforcement, a process expected to take several months. This study described both simulation and small site trials on LV networks where a combination of residential demands and EV charging would cause power flow or voltage violations of an LV feeder. The study found that installation of a battery could indeed avoid many of the violation events, though performance was better in simulations than in real site trials, for reasons including a timing offset, some battery malfunctions, and occasions of battery capacity limit.

Janssen et al [76] describe increasing network congestion in the Netherlands, largely driven by an EV roll-out, with PV-generation causing congestion in their selected case study network. They suggest the use of a *Relocatable* Energy Storage System (RESS), probably a fleet of EVs dedicated to this purpose, which could be moved, in quick response to congestion arising within the test network. The authors propose a method to optimally locate and move the RESS. This initial study yielded promising results: fewer mobile energy storage units would be needed, compared to stationary storage units, to provide adequate congestion relief in the network of study. The study does not suggest that such action might replace congestion in electricity networks with congestion on road networks, though it recommends further study to consider traffic and other issues.

Though comparing different forms of flexibility, and their effectiveness and cost-effectiveness is out of scope of this thesis, one reference of particular interest is mentioned here, as being relevant to the “overarching research question” posed in Chapter 1. Rinaldi et al used a “sector-coupling” model which represented both the electrical power system and the residential heating demands across their country, Switzerland [35]. The model incorporates both sectors’ demand profiles, electricity system constraints, and seeks to minimise total costs across both systems. The authors investigated the effect of adding different forms of flexibility , in the context of the country’s expected decarbonisation of heat and transport [35]. They found that widespread use of electric boilers for residential water heating, combined with a hot water tank, provided considerable flexibility to the electrical power system, especially when heating times could be optimised according to grid conditions. A heat pump roll-out would enable greater self-consumption of home PV output, but would increase the need for electrical storage on the grid in some scenarios, depending on roll-out rate, whether such heating system changes would be accompanied by retrofit to reduce overall heating needs. Demand-side response of wet appliances was found to have a relatively small effect on the grid’s need for electrical storage. The work found a trade-off between capacity of electrical storage, and capacity of distribution networks: the optimisation model considered 5 scenarios of distribution network capacity (from 95% to 115% of the current state), and found that the storage capacity required to avoid modelling constraints varied strongly in inverse correlation to DN capacity. This work describes a number of interactions between different forms of flexibility and low-carbon technologies. While appropriate or best-case solutions may differ between Britain and Switzerland, this studies generic findings – that the projected needs of any single form of flexibility are likely to be highly scenario-dependent – are considered likely to apply widely.

Altogether, the above 5 papers, from Northern Ireland, Germany, Switzerland and the Netherlands, describe the potential for batteries, in 2 cases together with PV, to support distribution networks in the context of electrification of heat and / or transport demands. While results were not always "perfect", e.g. simulation results differing from those from field trials, they provide useful insight into the strength, or otherwise, of economic arguments for the installation of batteries, and on how scenario-dependent a "lowest cost" decision regarding use and sizing of batteries, or alternative interventions, would be. These papers provide tools for network planners, and policy advice for governments.

2.2.1.3. Reliability improvement

This section describes studies in which a battery, alone or together with another technology, can deliver "reliability improvement" to electricity system demand users. In the first two papers, the authors explore how to assess battery deployment, as an alternative to other interventions, under circumstances in which a DNO would normally be required to reinforce or take other action, to maintain required level of security of supply (as set out, for example, in [77]). The context is similar to those of Section 2.2.1.1, i.e. seeking a "peak-shaving" type of service, but viewed from the angle of reliability metrics. The third paper suggests the use of mobile storage to deploy to areas affected by faults, to enable faster restoration of power.

Greenwood et al investigated the possibility of batteries improving network reliability, by "peak shaving", in a 2018 GB-based study [78]. This study investigates whether battery storage, in combination with real time thermal ratings (RTTRs), could defer reinforcement of a section of distribution network whose reinforcement would be triggered by peak demand flows. On some days such flows would exceed static line ratings for 3 hours in early evenings, a problem which expected demand growth would exacerbate. The authors use probabilistic methods to compute Expected Energy Not Supplied(EENS) metrics, at different seasons, using historical information about network reliability and demands. Calculations were repeated using both static line ratings and RTTRs based on weather information, and with a variously-sized battery to support supply of demand if needed. The study found that battery storage together with RTTRs could indeed maintain reliability metrics at an acceptable level for "at least 10 years", allowing deferment of reinforcement. The study found that use of RTTRs together with storage would require less cycling from the battery, likely to extend its service life, or alternatively free up the battery to perform other activities such as ancillary services provision at times. The work does not consider network limits as being a constraint to such activities. Regarding battery sizing, this work cites results from a real site trial, which found that battery energy capacity had a greater impact than power capacity on network reliability; furthermore, reliability of the battery itself was an important factor in EENS performance. The work does not include a full economic appraisal, but surmises that the battery may need to engage in multiple revenue streams to be financially viable. As in [79], the authors recommend market or regulatory changes to facilitate the use of battery storage in reliability provision; [78] also recommends development of additional markets for storage services.

London-based Konstantelos and Strbac also investigate the use of energy storage for providing a security contribution to networks in [79]. The work proposes a novel methodology to compute the "equivalent load carrying capacity (ELCC)", which they define as an additional demand whose connection could be enabled by the addition of energy storage, without increasing the "Expected Energy Not Supplied" metric of network (un)reliability, in the context of a small distribution network under single and double fault conditions. ELCC values are computed using numerous Monte Carlo simulations. The work found that energy storage can indeed provide substantial security to networks, but that the "capacity value" of energy storage is sensitive to factors including demand shape, islanding functionality and network redundancy. The authors recommend further work to facilitate comparison between the value storage and other types of network assets provide networks, and that energy storage assets should indeed be suitably rewarded for any security services they provide.

In [80], Zheng et al propose the application of *mobile* energy storage systems for occasional movement, for deployment to an area of network disconnected by a fault, in order to enable faster restoration of power. The envisaged situation would have the network able to operate in islanded mode under fault conditions, and connected renewable energy resources, whose use the mobile energy storage system would facilitate, when needed. In GB, such an approach could potentially be a longer term measure to improve resilience, especially in situations such as extreme weather events, for example Storm Arwen, in 2021, where extensive damage to overhead electricity lines in parts of Scotland and northern England left homes and businesses without power for up to 13 days [81]. This approach presupposes network rules allowing "islanded mode" operation of an area affected by a fault, and availability of sufficient local distributed generation resources to supplement the mobile energy store. Clearly this would be a significant departure from current grid operation in GB, though an initial trial of part of the concept is ongoing in rural Scotland [82].

Altogether, these three papers[78]–[80], two GB-based studies and one from Australia, are examples of small-scale battery, both alone and also with another technology, preserving or improving reliability of supply to network users. In the first two studies, the authors propose methods by which installation of storage can be considered as an alternative to other interventions, in circumstances where reinforcement or other action would be needed to preserve existing required network reliability standards. These authors call for an update to the GB regulatory framework, to facilitate storage deployment to be an option for this purpose. The third paper proposes to improve resilience from the status quo, by deployment of mobile storage post-fault, to facilitate more rapid power restoration: this approach would require networks' operation in islanded mode, which would be a significant change from current practices in GB, though may be a useful approach in the future.

2.2.2. Transmission and large distribution scale

Though papers in this and the preceding section all concern storage projects as a possible alternative to network reinforcement, in the face of changing patterns of generation and demands, there are some generic differences between projects of smaller and larger scales. Thus, these papers differ from those in the preceding section in several ways. In the papers in this section: -

- Maximum electricity flows through networks are *all* generation-dominated. This was the case in *some* of the studies in the previous section, but demand-driven maximum flows were more often reported
- The generation is from windfarms, rather than smaller-scale solar installations, as, to date, large windfarms have larger capacities than the largest of solar farms. (In two of the cases reviewed below, both in China, remote wind and solar resources are located relatively close to each other and are considered together.)
- The studies in this section aim to utilise more renewable generation, in order to reduce use of fossil fuel generation elsewhere on the grid, for economic and environmental reasons. In the following studies, this could be achieved by building a new windfarm(s) in locations of limited grid capacity, or by more fully utilising outputs from an existing renewable generators. Some of the studies in the previous section did aim to better utilise solar PV outputs, but the studies also described storage as potentially alleviating a broader range of problems, including declining network

reliability in the face of rising demands, or providing financial benefits to householders by increased "self-consumption" and reduced use of grid electricity

- A current approach to maintain system operability when larger-scale renewable outputs, usually wind, which at times exceed network capacity, is their curtailment. Curtailment of wind generation is commonly performed in parts of the GB grid (primarily in Scotland) as well as in other countries. While wasteful, this approach does enable connection of and generation from such windfarms pending wider network or other solutions. Curtailment tends not to be an option for the smallest generators e.g. rooftop solar, due to lack of regulatory and network communication infrastructure.
- While cost is a significant consideration in projects of all scales, costs are particularly important in some of the transmission projects here, where the storage project might potentially avoid a network reinforcement, or reduce the necessary capacity of a new network, of distances of hundreds of miles.
- Considering large-scale transmission projects, and the timescales necessary for their planning, consent and construction, any options, such as storage deployment, which may avoid or delay the need for network reinforcement, could potentially bring not only financial benefits, but be the only way to connect new renewable resources in a timely manner.
- Different types of storage technologies are relevant and practical at a regional or country-wide scale, compared to what one might install in a home or on a very local scale. Though the focus of this thesis is short-duration batteries, some of the reviews of large-scale storage assets, as existing or potential future installations, and serving on a regional or country-wide scale, consider PHS (still globally the most widely-deployed storage technology [45] or Compressed Air Energy Storage (CAES), and have insights relevant to this work.

The key findings of the individual papers follow below.

In the context of networks with high penetrations of wind, which is relevant to Scottish-based case study locations described in later chapters, Iranian and Irish-based researchers Maghouli, Soroudi and Keane [83] note that "*transmission network limitations are an almost universal impediment to the rapid deployment of wind capacity*", and that traditional reinforcement approaches take time and are costly. The authors suggest that deployment of storage is an attractive alternative to network reinforcement, and one which could be deployed faster. Several types of storage are mentioned, with batteries described as having the advantage of being able to offer fast-acting services such as *"frequency regulation… stability and reliability improvements"*, in addition to relief of network congestion. The authors propose a novel optimisation approach to best siting of storage assets on a network, with the objective function of minimisation of total social cost arising from costs of operation of power stations, load shedding, wind curtailment and pollution from conventional fuelled generators, using IEEE standard networks. This work assumes that the storage devices "*are operated centrally by the system operator*".

Plećaš, Xu and Kockar [84] describe a case study in which batteries are located in a wind-dominated part of the southern Scotland (SP Energy Networks' "SPD" area) distribution network, in which five windfarms and an energy-from-waste facility connect indirectly to the same GSP, whose capacity is limited by the 132kV/33kV transformers. In this case study, the DNO operates an Active Network Management (ANM) scheme, and all but one of the generators has a non-firm connection, i.e. can be curtailed by the DNO, without compensation, at times of network constraint. The study used one year of real data from the DNO, historical and estimated outputs from all generators, and estimates the curtailment of each generator during the year, under both normal conditions, and one "N-1" condition in which one of the GSP transformers is not available. The paper presents results for the single day of the year, the day of lowest demand, in which most curtailment occurred, under both normal and "N-1" conditions. The work compares a base case scenario (i.e. the network in its current state) with the addition of both a single battery, and also two batteries at different locations. This work provides insight into suitable sizing and location of battery to minimise curtailment under "worst case" conditions of lowest demand: the authors recommend further work investigating other network conditions. This work assumed that a battery is dedicated to reduction of curtailment.

Ademulegun, Keatley and Hewitt's, 2021 study of Northern Ireland's transmission grid [60] is also in the context of high wind penetration. The authors found that storage could substitute for or allow deferment of traditional reinforcement to reduce wind curtailment, and provides "*a pathway towards incremental network investment"*, though without a fall in battery costs, reinforcement would generally be a be cheaper option. Perplexingly, the authors also suggest storage could potentially address instances of wind generation curtailment for reasons of system operability, such as to increase system inertia or adhere to System Operator-set limits of non-synchronous penetration, without explaining how converter-connected battery storage could achieve this. (Clearly, any storage devices connecting to the electricity network via a synchronous generator, such as pumped hydro or CAES, would indeed increase synchronous penetration and system inertia.) The authors correctly identify a further limitation in batteries' utilisation of curtailed wind energy: their inability to operate for multi-day periods, over which high wind events often occur; they propose that longer-term energy could perhaps be provided by hydrogen production in the future. When considering sizing of storage facilities, the authors note the network generally would require more storage capacity over the windier winter months than at other times of year, but that storage assets could engage in other activities, primarily wholesale trades and ancillary services, when not engaged in constraint relief. The authors note the importance of appropriate sizing to avoid the batteries themselves causing additional constraints, especially arising from thermal ratings of network elements, a matter which is investigated in later chapters of this thesis. The authors do not address the matter of ownership of storage assets, but do state that their deployment much be financially feasible compared with alternative actions, and found that a mix of several revenue streams is not only possible, but in fact necessary for a battery's financial viability. Overall, [60] is a thorough and useful piece of work on an electricity grid with similarities to the GB grid, especially its Scottish part, which case studies of this thesis investigate in later chapters of this thesis.

In an Iran-based study, Salehi and Abdolahi [85] consider a variety of distributed energy resources, including energy storage in electric vehicles together with flexible demand, as an aid to both avoiding network reinforcement, and greater utilisation of renewable energy in network constrained areas. Using a "grey wolf optimisation", which they test on a modified 69-bus IEEE test distribution network, the authors report success in congestion alleviation and operational cost reduction, better control of voltage, reduced wind energy curtailment and thus reduced air pollution from conventional generation, as some generation is displaced by wind. The work assumes nodal pricing for all parties, and finds alleviation of constraints harmonises prices to the benefit of consumers. This work is clearly in a very different context to GB.

Hozouri et al in [86] seek the optimal siting of PHES from several candidate locations, together with their optimal power and energy capacities, to complement remote windfarms and reduce transmission congestion, using windfarm and network data from three sites in Iran. This work takes a combinatorial approach to seek lowest overall cost outcomes, with transmission reinforcement options also considered as both alternative and complementary actions to storage installation. The viability of the PHES stations are assessed using an arbitrage model, considering also transmission constraints potentially limiting their activity. The assumption that a central system operator is scheduling all generation is implied.

[87] is a Chinese study which discusses an aspiration to best "bundle" outputs from renewable generators (solar, wind and hydro) in remote areas together with each other and with storage facilities, in a situation of limited capacity of transmission lines necessary to conduct the electricity to demand centres, in the case of the study, over a distance of at least 1,700 km. The paper discusses the sizing of a PHS facility to complement the wind generation, to maximise wind utilisation at acceptable cost. [88], also in a Chinese context, suggests a Monte Carlo-based approach to identify locations where energy storage could provide most relief of transmission congestion, and then co-optimises scheduling of remote renewable (wind and PV) and storage resources, resulting in very similar overall system costs compared to traditional transmission reinforcement.

Olivos and Valenzuela review available research into how battery energy storage systems can be incorporated into Unit Commitment, in [89]. The article starts describi7ng the deterministic unit commitment problem, then state that in practice unit commitment is a stochastic problem, because of uncertainties in demands and renewable generation outputs. The authors consider various approaches to yielding adequate solutions within acceptable computing time. The article then describes various approaches that other studies have used to incorporate energy storage facilities into unit commitment calculations, in deterministic, stochastic, and security constrained variants of the problem, some of which use storage alone, and others where storage is used in combination with other interventions, such as demand flexibility. The authors believe that inclusion of battery energy systems will be essential to transition power systems to work with high penetration of variable renewable generation, but that "*excluding the inherent uncertainty in power systems could overestimate the performance and benefits of [energy storage systems]*". The authors mention inherent trade-offs between costs and robustness of solutions. Finally, they state that incorporating energy storage into unit commitment calculations will aid move "*towards more sustainable, resilient an energy* *efficient energy systems*", and state the creation of data repositories of battery energy storage characteristics would greatly facilitate such endeavours.

Altogether, these papers describe the ability of storage, of different types, to enable greater penetration of renewable energy, primarily of wind, by reducing peak flows through networks of limited capacity, and thus enabling greater overall energy transfers. One of the papers describes how incorporating battery energy storage into unit commitment calculations could aid system operation in the face of greater renewables penetration. Such interventions bring financial and environmental benefits to the system as a whole. One of the papers, in a similar context to parts of the GB grid, mentioned inherent limitations of battery energy storage to effectively reduce wind curtailment throughout high-wind events, often lasting many hours to several days, and suggest hydrogen storage may provide a future solution.

2.2.3. In summary: findings on different scales of storage projects

Despite the huge variations in scales of proposed projects, from using home-located batteries to support LV grids, right up to batteries and potentially PHS or CAES projects supporting transmission grids over distances of many hundreds of miles, these studies yielded remarkably similar findings. Batteries and other storage assets can support electricity networks, under different conditions, and provide a range of benefits, as summarised below in Table 2.

2.2.4. Comments on foresight and control of battery storage

A common approach in many of the aforementioned studies in Section 2.2 was to use historical or synthesised data for network variables such as voltage, renewable output, or demand power flow (as a baseline case), and then simulate the network with an added battery, or other energy store, and compare results to the base case. Many of these studies use deterministic logic to instruct battery actions under certain conditions, for example by instructing a battery to discharge at times of a voltage sag [72] or high demand flow on a feeder or a house [64], [70], or to reduce generation-caused network constraints [60], [84], respond to a network fault [79], or to maximise "self-consumption" in a house with a battery and rooftop PV, thus minimising electricity imports from and exports to the national grid [61]. Some studies incorporate such battery actions into a wider optimisation problem, such as to optimise voltage control across a whole test network [74], maximise use of renewable resources [86], or reducing overall social cost of the network (including costs of generator's fuel, and pollution). Some of the studies e.g. [67] did not state their methods in detail.

Table 2 Summary of services storage assets – small and large scale - reported to offer, in the reviews of section 2.2

	Service	Scale of storage project	
		Small scale	Large scale
1	Reduce peak flows – variable demand	Yes	Not reported but expected to occur
2	Reduce peak flows – variable PV or wind generation	Yes, solar	Yes, wind (and also solar in 2 cases)
3	From 1 & 2: reduce network congestion; reduce need for network reinforcement	yes	yes
4	From 1, improve reliability to demand customers	Yes, if demand breaches 'N-1' or even 'N' network capacity, and if other action not taken	Not reported
5	From 1 & 3: enable increased demands from electrification of heat and transport	yes	Not reported
6	From 2 and 3, increase use of existing and future renewable generation assets	yes	yes
7	From 6, reduced need for conventional generation – financial and environmental benefits	Yes, reduce purchases of grid electricity	Yes, reduce conventional generation despatch
8	Reduce cost by substituting for network reinforcement	In some but not all cases	In some but not all cases
9	Improve resilience to large disturbances, by facilitating faster restoration of power to demand customers	Potential service of mobile storage, in a future network designed to operate in islanded mode post-fault	Not reported

With the benefit of hindsight, or "known" conditions of a particular scenario, the battery or other energy store can indeed improve operation of networks. However, such studies may overestimate benefits that may be seen in actual deployment.

Some metrics are not known but can only be estimated, such as voltage and power flows in locations which lack monitoring. Even where monitoring exists or estimation is effective, knowledge of future values is inherently uncertain, for reasons including inaccuracies in forecasts of weather (affecting renewables outputs and in some cases demands), inherent variability of demand profiles, and the possibility of faults in equipment (e.g. generators, networks).

Held et al and Rowe et al [63], [75] conducted real trials on battery effectiveness in managing voltage violations on LV feeders. Held et al [75] found that a battery operating on a fixed timing schedule avoided around half of the voltage violations, significantly worse performance than that simulated, for a variety of operational reasons; measured performance, however, was high (avoiding 95% of voltage violation) in the case when battery was instructed by real measured feeder voltage data. This study shows the importance of having data, as opposed to crude forecasts to describe network conditions, and also some difficulties of running equipment in practice. Rowe et al [63] compare different control strategies for a battery dedicated to managing peak flows in networks, and refer to real trials in the south of England. They studied the effectiveness of "set point control" i.e. the use of a set value of a variable, such as voltage, which would trigger a battery import or export, both with and without forecasts. The authors compare these methods with a third "control with intuition" approach, based on historical and expert knowledge and offline algorithms. The authors found that "set point control", specifically the identification of the best value for a set point, was especially challenging on some LV networks, because of the "volatility" of their power flows. The authors also found that an offline algorithm dedicated to minimising peak flows worked well on feeders with more predictable flow patterns, and avoided expensive real-time monitoring.

Some of the studies in the preceding section acknowledge uncertainty in input data and attempt to accommodate it in their modelling, as did Maghouli et al's study [83] concerning uncertainties in wind generation.

In short, the findings in this section illustrate the potential of storage to alleviate a variety of network challenges. However, even when a storage asset is owned and operated by (or on behalf of) a network or system operator, the asset's "real world" behaviour may differ from that found in these studies, if there are limitations in its access to and quality of network data.

Access to network data, sometimes incomplete even for network owners, is likely to be more limited for other actors. Gissey et al [90] advise against independent ownership of storage, arguing that a system operator is best placed to make a decision between investing in storage or additional network capacity at a given place. Independently-owned storage assets, they believe, would inherently have imperfect information about electricity demands, which would impede a storage asset from having optimising its activity between trading, balancing actions and ancillary services, leading to sub-optimal behaviour.

The situation of storage assets being independently owned and operated is further addressed in the following section.

2.3. Closer to "real world": unbundled electricity system, independent battery ownership

The end of the preceding section describes how the effectiveness of storage assets to benefit networks operation may be limited by uncertainty in "real time" data and forecasts. However, an entirely separate reason for real battery actions to differ from predictions is that in an unbundled system, in which storage is independently-owned, the storage owner would be incentivised to maximise its revenue stream. This might or might not involve the same kinds of actions that would reduce costs and maximise benefit to the system, or enable maximum penetration of renewable energy, or minimise electricity bills at demand sites with their own on-sit renewables. The studies below investigate some of these situations. Most scenarios chosen involve large-scale storage assets, though one considers system-wide effects of residential batteries, and another considers portable storage units. A real-world example of actual battery deployment is included, and this section concludes with some of the insights from two large UK studies.

2.3.1. Studies contrasting storage unit behaviour according to different ownership models

The following four studies [91]–[94] investigate the behaviour of a storage unit in two or three scenarios of ownership or scheduling rules, to see if the storage unit's behaviour would differ. The cases are:

- acting to benefit the electricity network or system, by maximising "system welfare", penetration of remote renewable generation, and / or peak flows (from generation or demands)
- maximising "self-consumption", and thus minimising grid electricity consumption, for residential consumers with co-located battery and PV resources,

which are considered together with scenarios in which the storage unit responds to wholesale electricity prices: either by

- aiming to maximise its own revenue by engaging in wholesale trades, or by
- enabling co-located residential consumers avoid purchases at times of highest prices.

Hartwig and Kockar [91] investigate behaviour of storage on networks with wind generation, under different incentives. Using the IEEE 24-bus Reliability Test System network, and wind data from a Scottish windfarm, storage despatch is initially set to optimise system welfare, and then to optimise its own income. This work found that self-interested operation of energy storage assets was not detrimental to market welfare, compared to a "no storage" case. However, this study found that self-interested operation of a storage asset would differ from welfare-maximising operation: a self-interested storage asset would be "*incentivised to withhold some of their capacity during times when it will improve welfare the most*", as such behaviour would contribute to greater price volatility, an outcome detrimental to "market welfare", but which would increase the profits of the storage asset. Such effects would be exacerbated with greater network congestion. The work suggests that operation of storage by network or system operators could allow more efficient outcomes overall, but that unbundling arrangements of the GB power system prohibit such ownership. The authors suggest that other revenue streams, such as capacity payments, may be more appropriate for energy storage devices, to incentivise storage operators to act to maximise the welfare of the system.

A Canadian study by Bhattarai et al [92] investigates the use of Compressed Air Energy Storage (CAES), where PHS is infeasible, to complement wind generation. The work considers the CAES facility to operate in potentially two modes: first, to maximise utilisation of wind energy, which the authors suggest would be best implemented by an agreement between the CAES asset and windfarm owners; second, in arbitrage mode, where the asset's actions seek to maximise profit and are driven by price. In the first scenario, the asset is simulated to charge when wind output exceeds a set "reference wind output" value, which could be the capacity of the transmission line; the storage asset would discharge at times of wind below the "reference wind output". The authors suggest the storage facility gains revenue by selling the stored energy when transmission line conditions allow. In the arbitrage scenario, the CAES facility acts according to market price to maximise its income. Additionally, a reliability value is computed from sequential Monte Carlo simulations, which calculate loss of load and loss of energy expectations, and which are used to compute costs of unserved energy. Overall net benefit of the CAES is taken to be the sum of reliability and environmental services, plus any gains from arbitrage. Not surprisingly, operating the CAES to minimise wind curtailment achieved better metrics of wind energy utilisation compared to CAES in arbitrage mode; however the latter operation mode achieved better reliability metrics, and higher overall economic benefit. Clearly, specific results depend on scenarios, costs and prices, but the generic results, that storage facilities can be operated in different ways, with different objectives, and provide differing suites of results of financial and energy metrics, is a useful generic one.

A German study by Wanapinit et al [93] into the effects of widespread residential battery use, to 2045, contrasted batteries used in

- "self-consumption" mode – to maximise use of on-site PV, with
- "market oriented" mode - driven by wholesale prices, and
- "peak shaving" modes – controlled to reduce transmission congestion nationwide.

Not surprisingly, greatest system benefits were seen from batteries operating in "peak shaving" modes, mostly from reduced overall generation costs. However, even in this mode, there would nevertheless be need for future grid expansion to accommodate greater renewable penetration, especially as regional differences between renewable resources (as in GB, more wind in the north, and more solar in the south) and their outputs would continue. Transmission congestion would be greater with batteries operating in "self-consumption" or "market oriented" mode. The authors highlight the need for suitable signals to encourage home battery owners to utilise these assets in ways that would bring broadest benefits.

Denholm et al in [94] discuss the relative merits of siting storage near a locus of variable renewable generation, or near to demand centre, at three sites in the USA, where the transmission distances are great (between 780 km and 1400 km), and minimising the capacity of such connection was desired. The study discusses relative merits of "load-sited" energy storage facilities, compared with "wind-sited" storage, potentially owned by a windfarm, assuming in both cases that the asset needs to generate income. The study found that a "load-sited" storage asset would be more profitable, because it could engage in arbitrage, unrestricted by network limits. In contrast, the "wind-sited" storage asset, potentially owned by a windfarm, would have reduced revenues from arbitrage, as transmission constraints would limit its access to profitable trading at some times. However, such a storage asset would be most effective in reducing transmission congestion and enabling greater utilisation of remote wind energy, bringing financial and environmental benefits of reduced conventional generation, and potentially also avoiding transmission reinforcement costs. The work notes that remote-siting of storage can be an enabler for additional wind generation, as storage facilities are generally quicker to construct than long-distance transmission reinforcements.

Altogether, these studies found a storage unit aiming to maximise its income from wholesale trades *would behave differently* from one dedicated to network congestion relief, maximising renewable penetration, or other system-wide benefits.

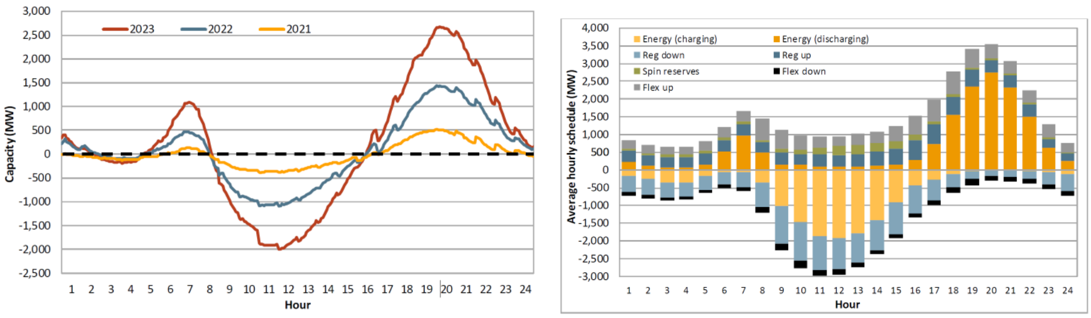
2.3.2. Studies considering storage only in “self-interested” mode

In the following studies, all in the USA, storage units would be, or are, engaging in wholesale trades and seeking to maximise their incomes. These studies discuss the effect storage deployment and behaviour, under these circumstances, would have on electricity network congestion, and in the last case, on other aspects of system operability.

Jorgenson, Denholm and Mai use proprietary software PLEXOS to conduct economic despatch of generators, and consider cases with remote areas of wind generation, at times curtailed because of transmission constraints, in [95]. Considering initially storage assets of 4-hour durations, to represent short-duration batteries, the study compares durations of wind curtailment with and without storage. Installation of short duration is projected to reduce curtailment, but by a small margin, because wind events commonly last for longer than 4 hours (with 40% of curtailment events lasting over 8 hours, and some lasting over a week). The work found that additional transmission capacity was far more effective than storage in reducing wind curtailment. However, the authors found a “symbiotic” relationship between transmission expansion and storage, where each increases the value of the other. The authors conclude that transmission expansion, even over long distances (500 -2000 miles in their case studies) is likely to be important to access remote renewable resources, though appropriately-located storage could be valuable in “niche” applications. Incomes from arbitrage alone would not justify the capital costs of storage assets in their case studies, but the authors suggest further work to identify additional revenue streams from ancillary services, which may serve to provide a more viable business case for storage assets.

He et al describe another USA-based study, [96], in California, whose nodally-priced electricity system results in significant locational price differences, sometimes over even short distances, prices and price differences which vary in-day. Their proposed scenario would have *portable* energy storage systems transported short distances in-day by truck, thus accessing higher and lower nodal prices, and more profitable trades. Their work suggests such portable storage systems could accrue revenues on average 20-30% higher than similar stationary storage systems, and where the best case would be 70% increase in revenues compared to a stationary system, apparently even allowing for transportation costs. Because the locational price differences arise from network congestion, and the authors cite congestion relief, and thus delay or avoidance of transmission reinforcement, as potential benefits from a portable energy storage system. The authors also note that the portable energy storage could serve multiple locations, and be far faster to deploy than traditional reinforcement. This concept is interesting, though clearly in a context of nodal pricing which does not apply in GB. As in Janssen al, [76] (Section 2.2.1.2), these authors neglect to mention the additional *road network congestion* such a development might cause.

A report from industry detailing contribution of actual deployed batteries onto a solar PV-dominated network is the California ISO 2023 Special report on Battery Storage [97]. This report documents an increase in battery capacity in the CAISO area from 500 MW in 2020 to 11.2 GW in June 2024, of which half is "physically paired" with solar or wind generation. The report found that "*batteries account for a significant portion of load during peak solar hours*", and *"batteries account for a significant portion of energy and capacity during the late afternoon and early evening when net loads are highest*" as illustrated in Figure 3. Batteries also provide a very significant contribution to balancing services. In this jurisdiction, batteries are independently owned and their activities must be financially beneficial for their owners. Clearly, California is a place where widespread battery deployment is helping with overall energy balancing and utilisation of solar energy.



(a) (b)

Figure 3 (a) Average 5-minute battery schedules (b) Average hourly battery schedules by product (2023). [97]

These studies, in similar fields, differ in their findings.

- The latter two find storage units, even behaving in a self-interested way, will reduce peak flows, network congestion, and potentially could delay the need for reinforcement.
- However, the first study found the opposite: that deployment of self-interested short-duration storage could not effectively substitute for transmission network

reinforcement when seeking to increase penetration of remotely-sited wind generation, though the two interventions would complement each other. One reason is the nature of the storage type and renewable generation: batteries able to charge for up to 4 hours could only store limited amount of otherwise-curtailed energy from the windfarms, whose high-output events tended to last for much longer.

2.3.3. UK studies of specific interest

This section summarises two sizeable UK [9] studies on the effects of storage on our electricity networks:

- GB study – Imperial College and the Carbon Trust ("Imperial"), 2016 [58]
- Northern Ireland study – PhD thesis, A.A.R. Mohamed [98]

The Northern Irish electricity system is part of the all-island-of-Ireland synchronous electricity system, Eirgrid, and is out of the scope of this thesis. However, this study is nevertheless useful, because the Northern Irish / all-island Irish power system is experiencing similar challenges to the GB one, especially its Scottish part, including:

- high wind penetration.
- decarbonising targets – similar to those of the UK's other home nations within mainland Great Britain

Both studies consider different types of battery storage: lithium ion, sodium sulphur and vanadium redox flow batteries. The Imperial report additionally considered two thermal energy storage technologies as possible providers of "distributed storage".

Imperial also considered

- large scale "bulk storage" technologies (Pumped hydro and compressed air), and
- "fast" storage (supercapacitors and flywheels) for specific system stability services in the milliseconds to seconds timeframes.

[9] The UK (which is the "United Kingdom of Great Britain and Northern Ireland") does not have a single electricity grid, because the province of Northern Ireland is geographically separated from Great Britain by the Irish Sea; Northern Ireland is geographically part of the island of Ireland, together with the Republic of Ireland. There is a single "all-island" electricity grid covering both jurisdictions on the Island of Ireland.

2.3.3.1. Potential benefits of storage deployment to the electricity system

Both studies considered potential benefits to electricity system from storage deployment. Both note benefits of storage assets complementing varying outputs of solar and wind, and also supporting increasing demands from electrification of heat and transport. However, the studies approach these matters in different ways.

Imperial calculate "whole electricity system costs", including capital and operational costs of all generators and despatch, including of storage, necessary to provide generation adequacy, and balancing and ancillary services, together with projected costs of distribution and transmission network reinforcements necessary. This was performed for several of National Grid's then Future Energy Scenarios. Taking the "Gone Green" scenario as the most pertinent for later-strengthened decarbonisation targets, this work found that significant cost savings, of around £2bn per year, in some of the scenarios where storage would be deployed, compared to a "no storage" base case, as illustrated in Figure 4. The bulk of cost savings arose from reduced fuel and carbon costs from despatch of gas and gas-CCS generators to provide balancing and ancillary services. Storage deployment was also projected to result in small cost savings from reduced distribution network reinforcements. It is interesting to note that no significant cost savings were projected in scenarios where the storage assets did not provide frequency response services, presumably because gas stations would be required to run to provide such services. It is also interesting to see that most solutions incorporating storage involved additional transmission network costs, albeit modest in comparison to overall savings. It is presumed that deployment of storage enables more distant renewables to be economically used, though they would require additional transmission reinforcement; unfortunately the report does not elaborate.

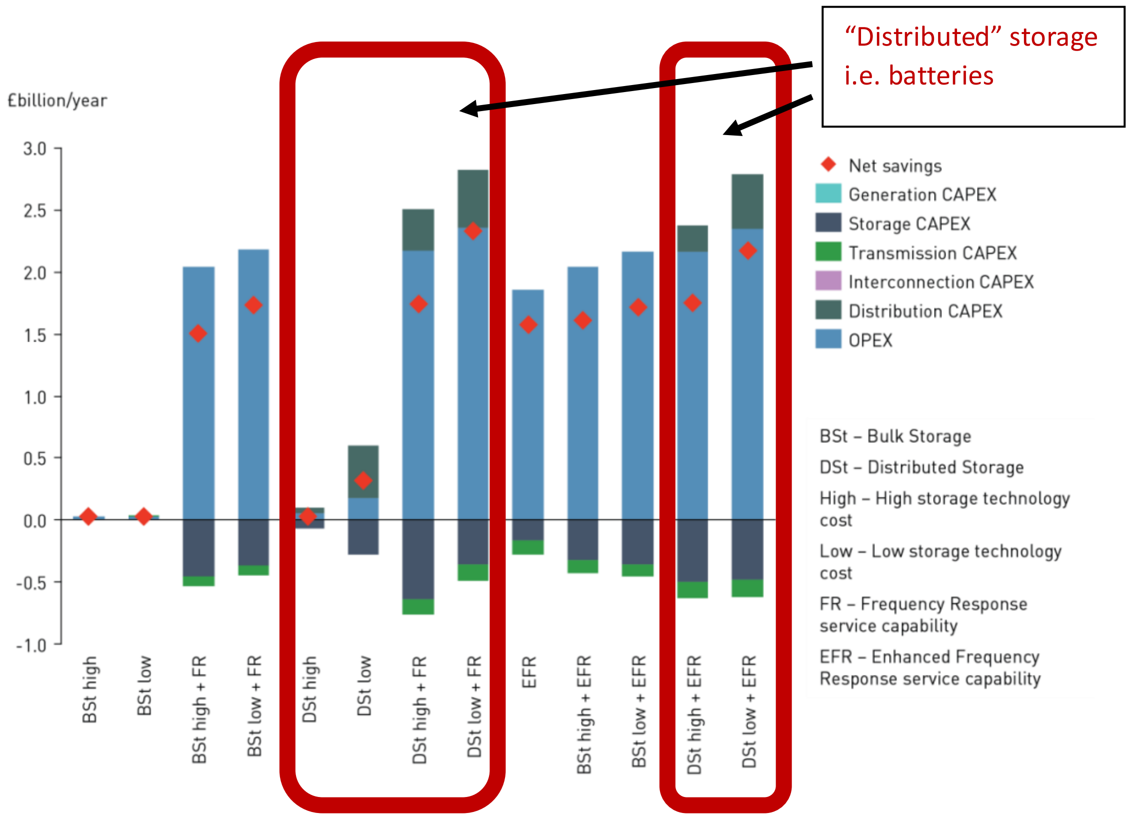


Figure 4 Annual cost saving across whole [electrical power] system from deploying different storage types in the ‘Gone Green’ scenario in 2030 against a base case of no additional storage. Reproduced from [58] with added annotations

Mohamed’s thesis does not consider “whole system costs”, but focuses on potential effects of battery storage to MV and LV networks, under scenarios of increased pressure from greater demands from electrified heat and transport, and increased distributed wind and solar PV generation.

His work explores the benefits that storage deployment could bring to MV and LV distribution networks in providing “grid-levelling” services to alleviate network constraints, and improve power quality, with particular consideration given to scenarios of low-carbon technologies roll-out, benefits that Imperial also state storage would bring. His work considered three generic scales of battery projects:

- *Grid-scale batteries connected to MV networks – with connected distributed wind and solar generation.* This work compares different optimisation algorithms to obtain the most beneficial sizing and placement of batteries. The batteries are assumed to be controlled by the DSO. He finds that suitably sized, placed and controlled batteries can indeed alleviate MV network congestion.

- *"Community-scale" or "street-level" battery deployment, on balanced and unbalanced LV networks*. This work found that suitably coordinated battery installations could support LV networks in the face of increase EV charging and PV generation, and avoid thermal overloads or voltage violations and improve power quality. Such services could avoid the need for conventional reinforcement.
- *Residential "behind the meter" battery storage*. He found that suitable controlled batteries could support the LV networks, under pressure from electrification of heat and transport, and also potentially reduce tariffs for residents. He also noted the importance of suitable cycling control to avoid premature battery ageing.

2.3.3.2. *Batteries engaging in self-interested price or tariff-motivated activity*

Both studies considered scenarios of batteries engaging in self-interested activity based on real time wholesale trade price or a "time -of-use tariff":

- Imperial state: *"the principal aim of energy price arbitrage is to store energy at low-demand and low-priced periods in order to discharge during periods of higher demand and price"*, and that *"'wrong time' electricity [e.g. from renewables, can] be stored and used at a later time of sufficient demand".* This work thus assumes that such price-incentivised trades would automatically benefit network and system operation.
- In contrast, Mohamed found that a significant roll-out of independently-operated residential batteries could negatively affect LV network operation, as high demand flows could be caused by coincident battery charging at times of low "time of use tariffs", such as a cheap night-time tariff (like GB's "Economy 7"). He recommends DSO efforts to incentivise residential battery owners to allow DSO to coordination or setting of rules limiting battery activity.

In later chapters, this thesis explores the assumption that the system wholesale prices are a suitable metric of system and network needs, and that price will inherently incentivise a self-interested storage asset to act in ways that benefit the electricity system and networks, as well as itself.

2.3.3.3. *Financial viability of battery projects*

Both studies consider the financial viability of battery projects from the point of view of their owners:

- Imperial consider the financial implications of co-locating a grid-scale (5MW and 25 MW) lithium ion battery, located at a windfarm and owned by a windfarm owner, under conditions of unconstrained and constrained network capacity
    - The battery is most profitable under unconstrained network conditions, as it can engage in wholesale and balancing trades
    - Under conditions of restricted network capacity, the battery's activities are restricted, but it provides value by reducing wind curtailment, as well as by engaging in wholesale and balancing trades. Their analysis suggests lifetime incomes from such activities would be exceed lifetime battery costs under at least some scenarios
    - The addition of frequency response services as a battery activity could potentially greatly increase battery revenues. The work does not address the ESO's possible reluctance to contract for services with a provider in an area of network constraint.
    - The authors also suggest that "layering" services may reduce battery degradation

- Mohamed considered the financial viability of stand-alone grid-scale MV-connected batteries, and their projected revenues under scenarios of three potential activities:
    - energy wholesale trades,
    - provision of ancillary services to the ESO, and
    - provision of local flexibility services to the DSO,
    - or a combination of the above activities.

  The work found that stacking of revenues, by engaging in multiple activities, was necessary for the battery's financial viability; i.e. that none of the individual activities provided enough income. The work proposed a control strategy to allow simultaneous activities without conflicts.

- Mohamed also considers the financial viability of "community scale" battery energy storage.
    - He found that despite network benefits, not all scenarios were financially viable. He also found that the DSO would need to pay the battery owner at

least £110/kWh, or £272/kW, for the battery project to break even over a ten year lifetime.

- Imperial examine a residential battery, with residential solar PV, engaging in self-interested activity
    - A battery only providing "load shifting" to utilise on-site PV would not generate enough income to cover the battery's lifetime costs
    - The authors also find such self-interested arbitrage is not "socially optimal", as it would leave greater share of network and other fixed costs to be borne by other network users (an outcome the Targeted Charging Review [99] later addressed through a change to network charging arrangements)
    - An aggregation of 90 households, each with the same type of PV and battery installation, but differing demand profiles, would gain greater value from the batteries, and such an arrangement would narrowly cover lifetime costs
    - An individual battery engaging in *either* frequency response services, or *"network support services"* (presumed to be some kind of DSO flexibility service), in addition to "load shifting", would be financially viable. Best financial outcomes would result from a battery engaging in all three activities.

- Mohamed also considers residential batteries with on-site PV. He found that though the PV system was financially attractive, the battery purchase was generally not financially viable under current conditions of costs and tariffs, over a projected 10 year battery lifetime, a similar result to Imperial's. However, Mohamed found a battery was attractive in some scenarios, where it provided continuity of supply to rural customers experiencing frequent disconnections.

2.3.3.4. Concluding comments

Overall, these two large studies, in a GB and similar context, both find that batteries and potentially other types of storage can indeed provide a plethora of benefits to the networks and system operation, while increasing penetration of variable renewable generation and newly electrifying demands are expected. However, both studies found mixed results regarding financial viability of battery projects; both studies also found that financial viability of batteries improves whenever they can engage in *revenue stacking*, i.e. perform multiple income-generating activities, a result relevant to analysis of "real" GB battery activities in

Chapter 3 Section 3.3.3. Whole [electricity]-system cost savings projected by Imperial were dominated by avoided costs of gas station despatch, with a small contribution from avoided distribution network reinforcement. Imperial assumed price signals would motivate a battery owner to act in the relevant electricity network or system's interest; Mohamed found to the contrary in the case of residential batteries, and recommended DSO control of battery assets to enable their best utilisation.

These works illustrate the variety of situations, locations, scales, presence of co-located resources, ownership, and control arrangements that could apply to battery projects, and their importance in determining the value, and any potential dis-benefits, that such projects may bring.

2.3.4. Regulatory views on storage in GB

Network operators, at both Transmission and Distribution level, have to model network flows and asses the effect that a new connectee would have on overall capacity. When considering connection requests from storage assets, which in GB are classed as generators, DNOs and the ESO have traditionally assumed "worst case" actions from storage sites, potentially exacerbating both import and export flows. Thus, network capacity allocated to a storage site would not be available to other current or future network users.

In an effort to enable faster connections to new electricity network customers, and faster progress towards Net Zero goals, the UK Government and Ofgem published a Connections Action Plan in November 2023 [100]. Included in its recommendations are changes to the way the ESO models the effect of Battery energy storage on electricity networks. *"Assumptions will be updated to recognise that [a battery energy storage system] (1) does not typically export at times of peak generation and import at times of peak demand; (2) does not act uniformly at all times; (3) operates for relatively short periods; and (4) modelling should be aligned across transmission and distribution".* The GB ESO's "Connections Reform" summary, December 2023 [101], states that the above changes have been incorporated into its Construction Planning Assumptions, modifications which NESO expects will facilitate faster connections for battery energy storage projects.

Outputs from chapters 3,4,5 and 6 of this thesis are relevant to some of these assumptions.

At Distribution level, such a change has not been enacted, however great pressure on network capacity remains in many areas. At time of writing, November 2024, there are over 80 GW of distribution network connections agreed for current and future batteries, according to the DNO Embedded Capacity Registers [37]–[42], as of November 2024. The network capacity agreed for these connections reduces capacity available for other potential future users, a situation the network owners' trade body, the ENA, finds highly detrimental to both network customers and to the achievement of Net Zero goals. In 2023, the ENA published Tactical Guidance for DNOs, endorsed by Ofgem, regarding connections of new storage assets [102], which instructs "less firmness of connection" for new connections to storage owners than to other types of users. This guidance is described further in Chapter 8.

2.4. Conclusions

There is a significant body of research into the many valuable services that batteries and other storage assets can and, in many cases, do provide to electrical power networks. Scales of operation range from residential scale batteries to large transmission-connected grid-scale facilities. A variety of approaches are used in the reported studies. Some use of real or simulated patterns of demand and / or generation, with deterministic rules governing battery behaviour. In others, storage asset is considered within a Unit Commitment problem. Numerous studies use optimisation to find the most beneficial size and / or location of storage assets on a network, often with a "lowest overall cost" objective. Some perform co-optimisations of storage together with renewable generation and transmission planning.

Most studies consider the storage asset owned and operated by or for the network or system operator, with rules that the asset must reduce network congestion or provide some other system benefit. Some perform a multi-objective optimisation, combining unit commitment with transmission planning, with storage assets being dedicated to aims such as maximum use of available renewable energy resources, minimising cost of energy, and minimising network congestion and / or reinforcement costs.

The greatest financial benefits of storage to electricity systems with significant renewable penetrations is found in several cases to be the displacement of more expensive and environmentally damaging generation with renewable outputs; in some cases ancillary service provision by storage enables further fossil-fuel generation reduction. However, storage deployment could also allow avoidance or deferment of network reinforcement, which in some cases was found to be a lowest cost solution.

In some cases, minimisation of transmission costs, or minimisation of overall system costs, was a constraint or an objective. In others, it was a potential outcome of the study. In the latter a variety of results were found, with many finding that battery energy storage could indeed help enable greater demands or greater renewable penetration, but struggled to compete financially with traditional reinforcement, though in some cases batteries were a lower cost option under certain specific circumstances. Some studies found that the best value from batteries was when they complemented additional network capacity, rather than were implemented as an alternative to reinforcement. Of relevance to later chapters was a finding, that short-duration batteries had limited effectiveness in reducing curtailment of wind generation, because high wind events tended to last for longer durations than the batteries were able to charge. However, numerous studies found batteries fitted well with shifting solar PV outputs to times of day of greater demand or higher prices, as is the current experience in the electricity system of California.

Some studies do consider the situation where storage assets are independently owned. Some studies compare storage assets operating for the benefit of the system, or perhaps a co-located renewable generator, with a "self-interested" mode in which they would seek to maximise their own incomes from trading. These studies all found that different behaviour would indeed be expected. All outcomes brought benefits to all parties, but a "self-interested" mode was most lucrative for the storage asset itself but not for the wider system. However, a real-world example from a heavily solar-dominated network found that independently-owned batteries are effective at "peak shaving", "time-shifting" and "load levelling" – storing energy (largely from solar generation) in the middle of the day, and discharging times of evenings peak system demands.

UK regulatory approach to storage is attempting to keep abreast with a sudden explosion in demand for battery connections. Traditional assumptions are for "worst case" behaviour, in which batteries may add to maximum flows when both charging and discharging. A year ago, the ESO's assumptions changed to no longer assume "worst case" behaviour from batteries: rather, that batteries are unlikely to exacerbate peak imports or peak exports from renewables. At Distribution level, the networks' trade association now recommends that DNOs grant batteries connections of "lower level of firmness" than would be normal for other users. Clearly further updates may be needed as a great roll-out of batteries is underway, evident from the GB DNOs' Embedded Capacity Registers, as discussed in the following chapter.

The body of research does not adequately address the question of "*what would a battery do, if connected in Britain, and how might it affect GB's electrical power networks?*", because they address neither the real financial incentives that are likely to drive the actions of batteries, nor the extent to which these incentives may coincide with or differ from a network or system operator's desired actions.

More specific unanswered questions include:

1. What activities might a short-duration battery *in GB* engage in (i.e. Research Question 1)? *This question is addressed in Chapter 3.*

2. Would greater deployment of batteries in GB *inherently* act in ways which:

(a) relieve network congestion, and potentially avoid or delay network reinforcement, and /or

(b) enable greater renewable deployment and / or greater demands from electrified heat and transport, with existing networks, and / or

(c) improve or maintain network reliability standards?

These questions inform Research Questions 2 and 3. The findings of Chapter 3 provide some background. Question 2(a) is addressed in Chapters 5 (regarding transmission congestion) and Chapter 6 (regarding Distribution congestion), chapters which begin to address questions 2b and 2c.

3. Do existing price signals in GB act as proxy signals of network congestion, and thus incentivise a self-interested short-duration battery to relieve network congestion?

This question – related to Research Question 2 - is addressed in Chapter 5, regarding transmission network congestion (for one nation-scale case study location), and Chapter 6, regarding selected examples of distribution network congestion (for six separate distribution case-study circuits).

4. Might greater deployment of batteries have any negative effects on networks?

This question – essential for answering Research Question 4 - is addressed in Chapters 5 and 6.

5. If deployment of batteries has any negative effects on networks, what mitigation measures might be appropriate? (i.e. Research Question 4)

Chapters 7 and 8 explore some potential approaches.

3. Chapter 3 Battery activities in GB: what are the options?

Chapter summary

There are over 3 GW of grid-scale batteries[10] deployed in GB in 2023/2024, with proposed future battery projects of aggregate capacity of at least 60-80 GW, and projects at the scoping stage of around 120 GW. The scale of current and proposed battery roll-out presents significant opportunities and challenges to system and network operators, and makes an understanding of batteries' likely actions important to understand.

Thus it is important for network and system operators to understand the likely actions of current and future batteries, to understand batteries' impacts on network and system needs.

Batteries and other storage assets can engage in a variety of activities to accrue income. Battery deployment in Great Britain began at pace with the introduction of Enhanced Frequency Response in 2017, the first GB frequency response service to require response within 1 second, whose providers were entirely batteries. Since then, various fast frequency response services allowed excellent financial incomes, of up to £800 / MW / day in summer 2022. However, greater numbers of batteries entered these services markets during that year, and clearing prices fell to around £200-£300 / MW /day by the end of the year. Under such conditions other revenue streams potentially become more attractive. By the end of 2022, over 20 grid scale batteries were operating in GB and had engaged in wholesale trades during the year. Some of these batteries also performed Balancing Mechanism trades, but generally far less often. Another potential income stream is the Capacity Market. Network Use of System credits for exporting at times of high network demand charges, or, for batteries sited behind the meter of a large demand site, avoidance of "red band" and / or "Triad" network demand charges, may also supplement other income streams. Provision of DSO flexibility services is a further option in some localities.

In short, there is no single answer as to what activity a rational battery would engage in. Astute operators are likely to engage in multiple activities, and to move between markets, as mentioned in Chapter 2. Engagement in wholesale trading activity was an activity numerous

[10] No accepted definition of "grid-scale batteries" has been identified. In this thesis, the term means "batteries of a size (MW or MWh) which can independently offer services to an electricity system operator or a distribution network / system operator, or which can participate in wholesale trading activities".

batteries engaged in during 2022, suggesting it was a financially viable option. This activity is investigated in the following chapter.

3.1. Introduction

As outlined in Chapter 2, batteries and other types of storage providers have the potential to provide a wide range of important services to electrical power systems, summarised, for example, in [56]–[58], [103].

In Britain, batteries and other storage assets are classed as generators [104]. Under the rules of Britain's electricity system unbundling and privatisation, transmission owners must be separate from owners of generation [105], a principle which has been extended to distribution network owners and the later-separated ESO. Thus (with few exceptions[11] [106]), batteries and other storage assets cannot be owned and operated by network owners or the ESO. Operators of networks and the system, however, can enter into contracts with storage owners for the provision of services. CEER, the Council of European Energy Regulators, states such separation of ownership is desirable, because, in its view, any participation of a DSO in a competitive market, for example for a flexibility service, would be a conflict of interest and would introduce a risk of market distortion, a risk that *"must be avoided wherever possible"* [107].

Thus, activity of any battery or other storage asset needs to serve the needs of its owner, for whom its actions must be financially viable.

This chapter presents the current level of deployment of batteries (and other large-scale storage facilities) in GB, and of projects awaiting connection. It continues with an overview of the range of activities batteries engage in, in several countries, including within the GB system. This chapter then describes battery activity, or potential for activity, in the following activities within the GB system, with an emphasis for conditions during 2022, the year of study:

[11] Exceptions where a network owner may own a storage asset include: Category A - storage assets on geographical islands (other than mainland GB); Category B - storage assets for a "specific authorised activity" such as uninterruptible power supply or emergency response (such assets being expressly prohibited from engaging in any market activity); and Category C - cases specifically authorised by the regulator. Network owners seeking Category C authorisation would need to demonstrate they have taken reasonable steps to find a market based solution, their ownership of a storage asset "provides the most economic and efficient solution", and that proposed arrangements minimise the risk of discrimination or distortion in markets. Permission may also be granted for innovation projects (with past examples including [279], [280]).

- Frequency regulation, frequency response and reserve services – traditionally the main activity and income stream for batteries
- Balancing Mechanism and wholesale trades
- Capacity Market
- Use of System network charges – potentially credits and / or reduced charges
- Flexibility services for DNOs / DSOs

This chapter concludes with a summary of the main options for a battery owner, with an indication of potential revenues from some of these activities.

3.1.1. Battery deployment in Great Britain

The deployment of grid-scale batteries in GB has risen from near zero in 2016 to over 3 GW, according to the UK Government's Digest of UK Energy Statistics, at time of writing (November 2024), surpassing the capacity of pumped hydro storage in 2023, as shown in Table 3 [36].

Table 3 Grid scale battery[12] deployment in the UK[13]. DUKES 2024 table 5.16. [36] All figures in MW[14].

Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
PHS	2,744	2,744	2,744	2,744	2,744	2,744	2,744	2,744	2,744
Battery	0	0	108	487	676	914	1,280	1,933	3,465

The capacity of grid-connected batteries is expected to rise considerably. Table 4 lists aggregate battery capacity totals sourced also from UK Renewable Energy Planning Database (REPD) October 2024 [108], the NESO's Transmission Entry Capacity (TEC) Register [43], and Embedded Capacity Registers (ECRs) from all the DNO owners GB [37]–[42]. All sources were accessed 19-21 November 2024. These sources suggest future projects of stand-alone batteries totals of 59 GW (REPD), 82 GW (DNO ECRs, of distribution-connected projects), and the NESO lists 11 GW of proposed transmission-connected projects, and almost 120 GW of such projects classed as "scoping". Even these figures are likely to underestimate aggregate

[12] This DUKES data table states that small 'behind the meter' batteries such as those in domestic or commercial properties are excluded.
[13] DUKES figures include Northern Irish as well as GB-located assets.
[14] Total capacity in MWh is unavailable. MWh capacity from the largest station, Dinorwig, is estimated at 8.6 GWh, based on 5 hours of operation [281]. The other station owners do not state durations of operation.

capacity of proposed projects because some of the project entries, especially on the REPD register, do not include a MW capacity. Further details are appended Chapter 3 Annex 1.

Table 4 Current and projected aggregate capacity of grid-scale batteries in GB, by development status. DUKES figures include all types of battery installations. REPD and NESO figures refer only to stand-alone battery projects. DNOs' figures refer to all battery projects in which the battery is the primary energy source.

<table>
<tr><th rowspan="2">Operational status</th><th colspan="4">Aggregate battery capacity, MW[15]</th></tr>
<tr><th>DUKES [36]</th><th>REPD [108]</th><th>NESO: TEC Register [43] (Transmission-connected only[16])</th><th>DNOs: ECRs [37]–[42] (Distribution-connected only)[17]</th></tr>
<tr><td>Operational / Built / Connected</td><td>3,465</td><td>2,080</td><td>706</td><td>3,279</td></tr>
<tr><td>Under construction</td><td>-</td><td>3,837</td><td>230</td><td rowspan="3">82,042</td></tr>
<tr><td>Consents granted</td><td>-</td><td>24,958</td><td>4,594</td></tr>
<tr><td>Planning decision awaited</td><td>-</td><td>30,083</td><td>6,452</td></tr>
<tr><td>Scoping</td><td>-</td><td>-</td><td>119,687</td><td>-</td></tr>
</table>

Even allowing for likely project attrition, the scale and pace of this expected roll-out of batteries to the GB grid presents great opportunities, but potentially also challenges, especially for distribution networks, to which most of the proposed projects are likely to connect. It is therefore important that network and system owners and operators have some foresight of batteries' likely types of activity, to inform decisions about network and system needs.

The duration of the batteries (i.e. the duration for which they could discharge, i.e. export energy, at their full rated capacity, without suffering accelerated degradation or damage) is generally not listed in any of the above data sources. However, as stated in Chapter 1, Rho Motion and The Faraday Institution reported in 2023 that the majority of UK batteries are lithium-ion based, a finding the IEA reports is also the case world-wide [44], [45]. [44] reports lithium batteries having discharge durations of 30 mins to 4 hours. [109] cites the US

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[15] DUKES figures include Northern Irish as well as GB-located battery projects. All other fields are for GB projects only.
[16] The figures are using "Direct Connects" totals from the TEC register, excluding projects listed as "Embedded".
[17] All figures are for projects of capacity 1 MW or greater. The DNO ECRs list only two project statuses: "Connected" and "Accepted to connect". "Accepted to connect" refers to agreement with the DNO, not Planning authorities. The totals listed here use ECR column "Maximum Export Capacity (MW)" for "Connected" aggregate capacity, and column "Accepted to connect registered capacity (MW)" for "Accepted to connect" aggregate capacity.

Department of Energy Global Energy Storage Database [110], accessed November 2022, for durations of various storage technologies, and stated the median duration of deployed lithium ion battery projects was 1.3 hours, with the 25th and 75th centile durations being 0.7 and 3.8 hours respectively. (Lead acid battery projects had similar durations: median, 25th centile and 75th centile durations of 1.6, 0.7 and 4.1 hours, respectively).

Looking forward, the IEA expects innovations in lithium ion batteries to continue, and that longer-duration flow batteries "*could emerge as a breakthrough technology for stationary storage*". Similarly, Rho Motion and the Faraday Institution list various lithium ion battery technologies as being "current", with other short-duration variants on this technology expected within 1-5 years, and that several types of longer-duration (hrs-days) flow batteries may become commercialised in 1-6 years (from Sept 2023).

Thus, it is expected that batteries deployed in GB will continue to be those of a similar, short duration, unless or until longer-duration batteries or other types of storage become more economically attractive. Thus, this chapter concentrates on likely activity of short duration batteries, of duration up to 4 hours.

3.1.2. Potential revenue streams for batteries and other storage assets

Schmidt and Staffell state in [109] that "there is no such thing as a typical electricity market"; that markets, structures and incomes vary across jurisdictions. This source includes a chart which gives broad comparisons between main revenue streams available for storage (of all types) in Great Britain and three other countries, based on 176 individual publications in 2018 and 2019. Each data point on this chart refers to a valuation of a grid service reported among the studies reviewed.

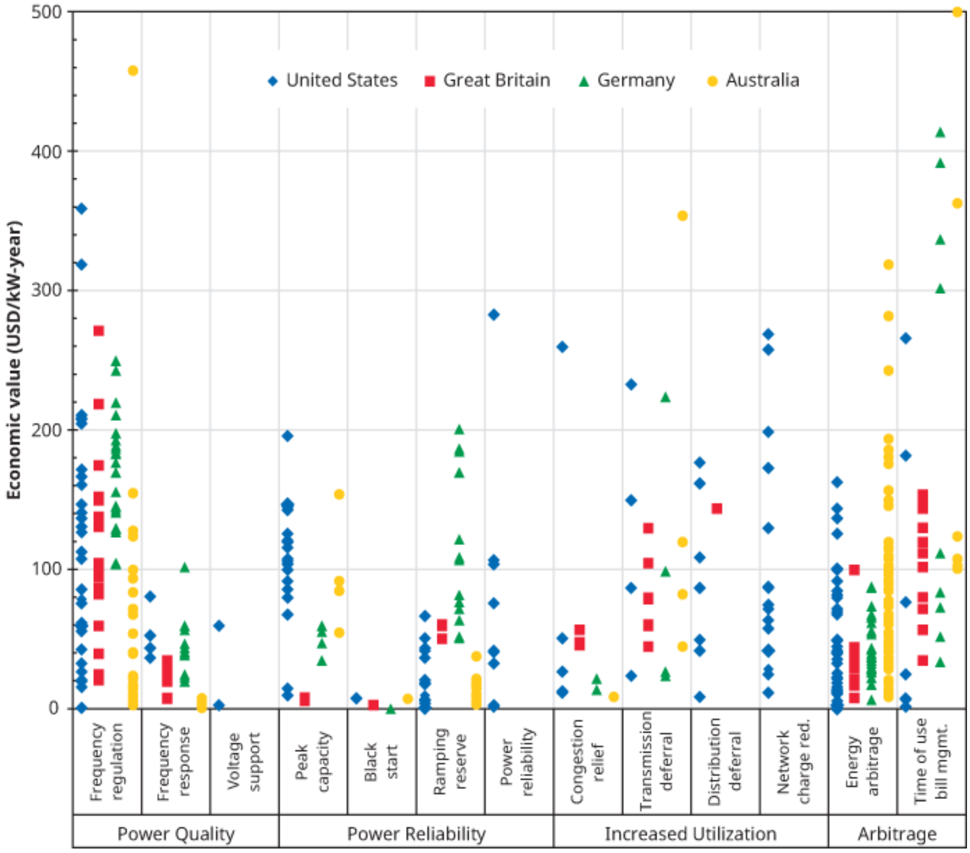

Figure 5 Reproduced from Figure 6.2."Market value, Making money" in [109][18]

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[18] The following notes are stated in [109] for their Figure 6.2, reproduced above as Figure 5.

The value of different electricity storage applications across four major markets. Data are taken from 176 individual valuation studies and published market transactions as compiled by Balducci for the United States and Housden for Great Britain, Germany, and Australia. The specifications of each application vary across the individual studies and are not necessarily aligned with the definitions given in this book. The scope of each study also varies in terms of the timeframe and market considered (as the United States and Australia have multiple electricity markets). All values are presented in USD/kW-year even for applications which are remunerated by energy discharged rather than power capacity, as this then incorporates device utilization. A value of 100 USD/kW-year can be interpreted as a 1 MW system receiving USD 100,000 annual revenue from service provision.

Figure 5 cites two references: The first, [111], written in 2018, sets out a taxonomy of energy storage value streams, in the context of electricity systems and their associated markets in the USA. The second reference[19], with European and Australian comparisons, is a 2019 UK-published report, which unfortunately is not available.

Given the lack of availability of source material, and the change in some of the services, charges, and prices in the GB power system since the source material was written, the "economic value" figures in Figure 5 are viewed with caution, though they nevertheless provide a useful illustration of revenue streams which may be of interest to storage owners.

In this chart, the reader can see

- estimates of the potential economic value of 13 different identified services or activities which storage assets could engage in, in the four markets
- an illustration of which activities may be more or less common, and more or less financially rewarding in the four markets
- an indication of the range of remuneration, in some cases a very wide one, for provision of the same or a similar service (e.g. "frequency regulation"), even in the same market
- both similarities and differences in services, products and opportunities across the four markets.

The main value streams from this chart which are applicable in GB are listed in Table 5. This table refers to the sections of this chapter (and following chapter) where the services are elaborated. Examples of potential revenues from all relevant services in GB, where enumerated, are summarised at the end of this chapter.

[19] Housden J. *An Evaluation of Energy Storage Profitability in the United Kingdom, Germany, Australia and the United States* (London: Imperial College London, 2019).

Table 5 Potential value streams for storage assets, based on Figure 5: services and revenue streams available in GB

Potential value stream listed in Figure 5	**GB service or activity**	**Comments**	**Section in this chapter / chapter in this thesis where elaborated**
Frequency Regulation & Response	Frequency response services, Fast Reserve		Section 3.2
Voltage support	Providers may be accessed via the Balancing Mechanism. Pathfinder ancillary services trials in a few locations	Not identified in Figure 5 as a relevant revenue stream for storage in GB	Not elaborated
Peak capacity	Capacity Market		Section 3.4
Black start	Black start / restoration	Figure 5 **presumed to** refer to synchronous hydro / PHS service providers in GB	Not elaborated
Ramping reserve	Longer duration reserve services	Relevant to longer-duration PHS / hydro rather than short-duration batteries	Not elaborated
Congestion relief	Balancing Mechanism – ESO actions to manage grid constraints		Section 3.3
Transmission deferral			Section 3.3
Distribution deferral	Potentially a DSO flexibility service		Section 3.6
Network charges reduction	Transmission System Use of System (TNUoS) or Distribution Use of System (DUoS) charges	Not identified Figure 5 as a relevant revenue stream for storage in GB.	Section 3.5
Energy arbitrage	Energy arbitrage, more commonly called “wholesale trades”		Section 3.3, Chapter 4
Time of use bill management	Reduction of TNUoS and DUoS charges or gaining of credits	Potential for the highest incomes from this revenue stream has much diminished since 2021.	Section 3.5

An “Energy Storage Network” industry conference, held in Britain in January 2023 (in part online), discussed options and revenue streams for storage assets, in a GB context [112]. Frequency response services, long the main revenue stream for batteries, were being offered by increasing numbers of market entrants, causing market saturation and lower prices towards the end of 2022, conditions that were expected to persist. Industry participants believed that December 2022 was the first occurrence of conditions in which storage assets could accrue higher overall incomes from wholesale trades than from frequency response provision. The presenters and delegates discussed the need for storage assets to jump between different revenue streams (frequency response, potentially reserves, and wholesale and Balancing Mechanism trades), ideally in-day, to achieve the best revenues. There was agreement that future revenue streams were increasingly difficult to predict.

The rest of this chapter discusses the most relevant activities, from the perspective of an owner of a battery located in GB. These activities are: frequency response and reserve services, wholesale trades and Balancing Mechanism, Capacity Market, Use of System avoided costs or credits, and DSO flexibility services. Potential incomes a battery could accrue from some of these services are enumerated, and summarised at the end of this chapter in Table 14 and the rest of Section 3.7.

Three case study periods during 2022 have been selected for detailed analysis in this and the following chapters, as shown in Table 6. The year 2022 was chosen, as the year in which this study commenced, and also a year of exceptionally volatile wholesale prices at times, making it a year of great interest. Case study periods were selected to illustrate different seasons, with different conditions of weather, in particular wind generation, and differing patterns of system demand. The wholesale electricity price is fundamental to the work in the following chapter, of Scottish wind generation availability to the work which follows in Chapter 5, and of patterns of wind generation and demands in selected local areas in Chapter 6,7 & 8. Case study periods, rather than the whole year, were chosen, because of lack of access to a wholesale price dataset, as described further in the following chapter.

Table 6 Case study seasons

Season	Start date	End date	Scottish BM[20] Wind availability (combined onshore and offshore)	Wholesale electricity prices	Weather
"Summer"	26 May 2022	29 Jun 2022	Low for most of the period, with several short-duration high-wind episodes	Relatively low and with low volatility for most of the time, with a few episodes of small price spikes or dips.	Mostly sunny and warm
"Autumn"	25 Sept	29 Oct 2022	High for most of the period, with brief lower-wind interludes.	Significant volatility during early part, with prices becoming lower and calmer towards the end.	Mild and windy
"Winter"	17 Nov 2022	21 Dec 2022	Moderate to fairly high at the very start and end of the case study. A prolonged (cold) low-wind period in the middle, with near-zero wind for a few days.	Initially moderate. Very high price spikes during the early evening peak on a few days during late Nov and early Dec. The early December cold snap saw high prices with a large diurnal price range. Prices fell sharply near the end of the case study period, coinciding with a change in weather.	Mild and windy, then very cold and calm, ending on milder windier weather

This chapter also summarises the activities of grid-scale batteries that were active in GB during 2022, during the whole of the year, and in particular during the case study periods. Potential incomes a battery could accrue from wholesale trades during the same case study periods are enumerated in the following chapter.

[20] Balancing Mechanism (BM) is described in Section 3.3.3.3

3.2. Frequency Regulation, Frequency Response, and Reserve services

Frequency regulation, frequency response and reserve services are among the suite of ancillary services which the System Operator procures as it needs. These services are necessary to keep the steady state system frequency within the statutory frequency range (within 0.5 Hz of 50 Hz), and to limit the magnitude and duration of transient frequency deviations, as set out in the Security and Quality of Supply Standard (SQSS) [113]. The roles of these different services are illustrated in Figure 6 and Figure 7.

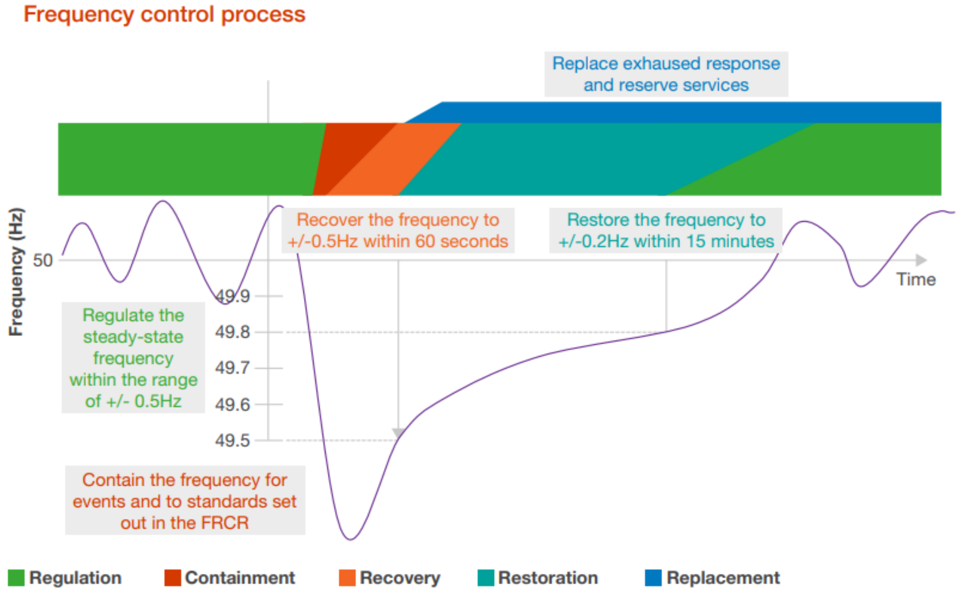


Figure 6 Frequency restoration process. Reproduced from NGESO's 2022 Operability Strategy Report, [114]

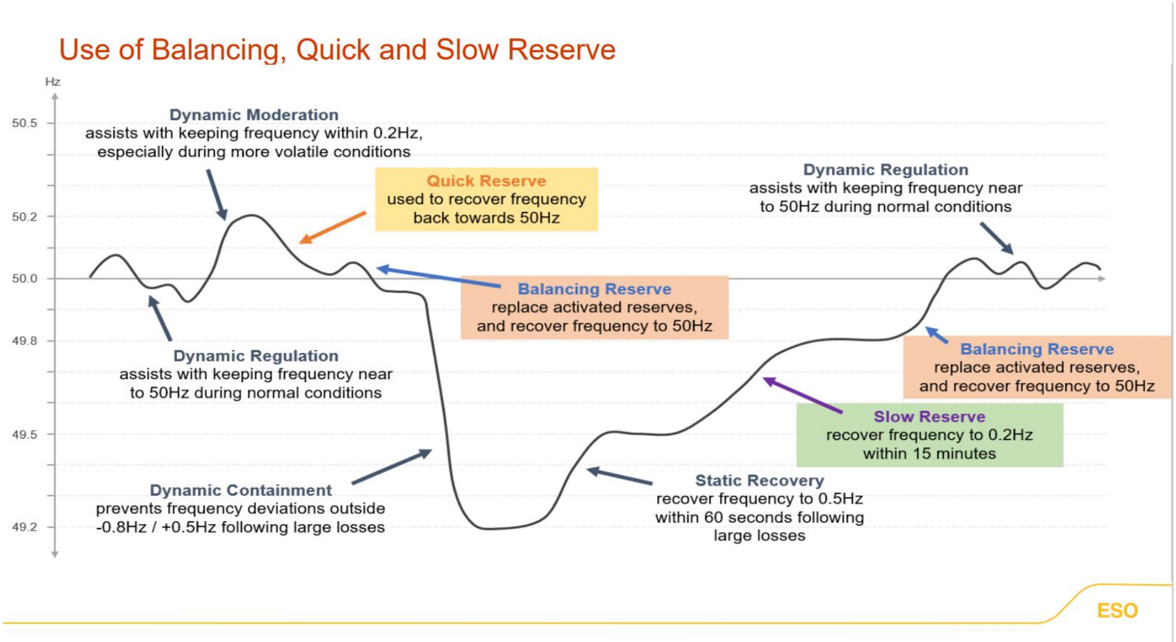


Figure 7 Overview of Frequency regulation, frequency response and reserve services. Reproduced from NESO "Response Reform Roadshow slides", 2024 [115]

3.2.1. Introduction to GB's Frequency Regulation and Frequency Response services

Frequency *regulation* services Dynamic Moderation and Dynamic Regulation are designed to operate *pre-fault*, as illustrated in Figure 6 and Figure 7, as set out by the ESO in [116].

Frequency *response* services are *post-fault* services, known as "Frequency Containment Reserves", which NGESO's Grid Code defines as: *"in the context of **Balancing Services**, [Frequency Containment Reserves are] the **Active Power** reserves available to contain **System Frequency** after the occurrence of an imbalance"* [117], also illustrated in Figure 6 and Figure 7.

Frequency regulation and response services all respond automatically to pre-defined conditions of system frequency, with response times ranging from sub-second (Dynamic Containment and Dynamic Moderation) to 30s ("secondary response", part of the Mandatory Frequency Response (MFR) and Firm Frequency Response (FFR) portfolios). Response is time-limited, required to last from 20s (MFR and previously FFR, "primary response") and 60 minutes (Dynamic Regulation) [118]–[123].

Frequency response services have always been necessary for secure operation of a power system, to respond to a sudden major disturbance and prevent system frequency falling (or rising) outside of agreed limits. Declining system inertia is necessitating faster-acting response services [29], a need met by NGESO's introduction of new faster-acting frequency response products in recent years. Batteries are particularly well-suited to delivering fast and time-limited response and are among the services providers.

3.2.2. Frequency response services: recent historical background and products overview

Firm Frequency Response (FFR) has been the "*traditional frequency response suite used for balancing grid frequency in real time*" [121]. Most products within this portfolio have been discontinued as the faster-acting "end state [frequency regulation and response] services" have been introduced, described below. Mandatory Frequency Response [122], [124] has long been in place, but is usually procured from thermal generators, requiring them to increase (or reduce) output at times of system need, and is of little relevance to batteries.

Enhanced Frequency Response (EFR) was the first service in GB that required response - to both high and low frequency events - at speeds of up to 1 second, including a maximum activation delay of 500 ms, with response to be sustained for 15 minutes. National Grid ran a single auction for Enhanced Frequency Response (EFR) in 2016, for contracts of four years [125]. National Grid stated it was agnostic to technology, location and connection voltage of applicants, and allowed bidding from plants not yet operational. Delivery started between April 2017 and March 2018 [126]. All successful participants were batteries [126], [127].

Following the ESO's reviews of ancillary services in general in 2017 [29], focusing on frequency response and reserve services in particular during 2017-2019 [128]–[130], a suite of "end state" frequency response services was developed, which consists of three products [131]:

- Dynamic Containment (DC),
- Dynamic Moderation (DM),
- Dynamic Regulation (DR).

All three services have "high" and "low" variants, responding to high and low frequency events, respectively, i.e. "low" service (e.g. "DCL") would deliver energy (or reduce consumption), and a "high" service (e.g. "DCH") would reduce generation or increase energy import. "Low" and "high" response services are procured separately. DC and DM require response to commence within 0.5s, and full power within 1 s; DR can react more slowly, starting within 2s and delivering in full within 10s. National Grid ESO launched the first product of the suite, Dynamic Containment [118], in 2020, and in its current form in autumn 2021. Significant volumes of DC are procured throughout every day. The complementary services Dynamic Moderation (DM) [119] and Dynamic Regulation (DR) [120] were launched in spring 2022. National Grid publishes market data for the DC, DM and DR auctions [132], [133], including participants, prices offered and clearing prices. All prices are for availability; any energy delivered is reimbursed according to the *imbalance price* for that Settlement Period[21].

The rest of this section focuses on potential revenues a battery may accrue from the "end state" frequency response and regulation services DC, DM and DR. This section aims to give an indication of revenues a battery may accrue from frequency response services, for comparison with other activities, rather than an in-depth comparison of alternative frequency response services. Thus, incomes from FFR, a service which is being phased out[22], and other frequency response services, are not enumerated.

3.2.3. "End state" frequency response services: Dynamic Containment, Dynamic Moderation, Dynamic Regulation

3.2.3.1. Potential revenues: Clearing Prices

All three products are traded on in an online auction, which run between 2 weeks and one day ahead. Service provision is in 4-hour "EFA" (Electricity forward allocation) blocks, timings shown in Table 7.

Table 7 Timings of EFA blocks, for DC, DM and DR provision

EFA block	Start time	End time
1	23:00*	03:00
2	03:00	07:00
3	07:00	11:00
4	11:00	15:00
5	15:00	19:00
6	19:00	23:00

* Preceding day

Timeseries charts for the clearing prices of availability payments for all three products, low and high, from October 2021 through till May 2023 [133] are displayed in Figure 8. This figure shows the timeseries and trend, over a year and a half, of the clearing prices for the six services, for each EFA (i.e. time of day) block.

[21] Imbalance prices for any settlement period are influenced by any Balancing Mechanism Bids and / or Offers the ESO accepts, and the costs of any other balancing services. More information is available from Elexon here [282]
[22] Only "Static Firm Frequency Response is currently procured, as of March 2025, as shown in [116].

Figure 9 shows summary statistics for clearing prices for each product, for each EFA block, throughout the same period, or, for the products which commenced activity later, for the duration of their period of activity.

Median prices for the products ranged from around £0 to £20 / MW/h availability price, with slightly higher mean prices. The better performing products (DCL, DRH, DRL) had occasional much higher prices, exceeding £50/MW/h, and very occasionally, £100, in the case of DRH and DCL.

From autumn 2021, there were relatively high and consistent clearing prices for DCL, the highest-value service, up until April 2022. Thereafter, prices for DCL were variable, with the highest prices normally for EFA block 5 (early evening) sometimes exceeding £100/MW/hr. From October 2022 into spring 2023, high price spikes occurred occasionally, but prices generally remained low. DRL and DRH had similar patterns from their introduction in April 2022. DCH, DML and DMH had much lower prices.

Prices varied considerably between EFA blocks on some days, with late afternoon EFA block 5 having the highest prices for DCL, DRH, and occasional price spike for DCH. EFA block 3 (morning) had occasional high price spikes for DCL, and EFA 2 (very early morning) for DCH.

Mean daily revenues for each of the products, over the date range from 1 October 2021 (or the date at which the product was launched, in the cases of DM and DR) up until 3 May 2023, are shown, split by EFA block, in Figure 10, and in total across all 6 EFA blocks, in Figure 11.

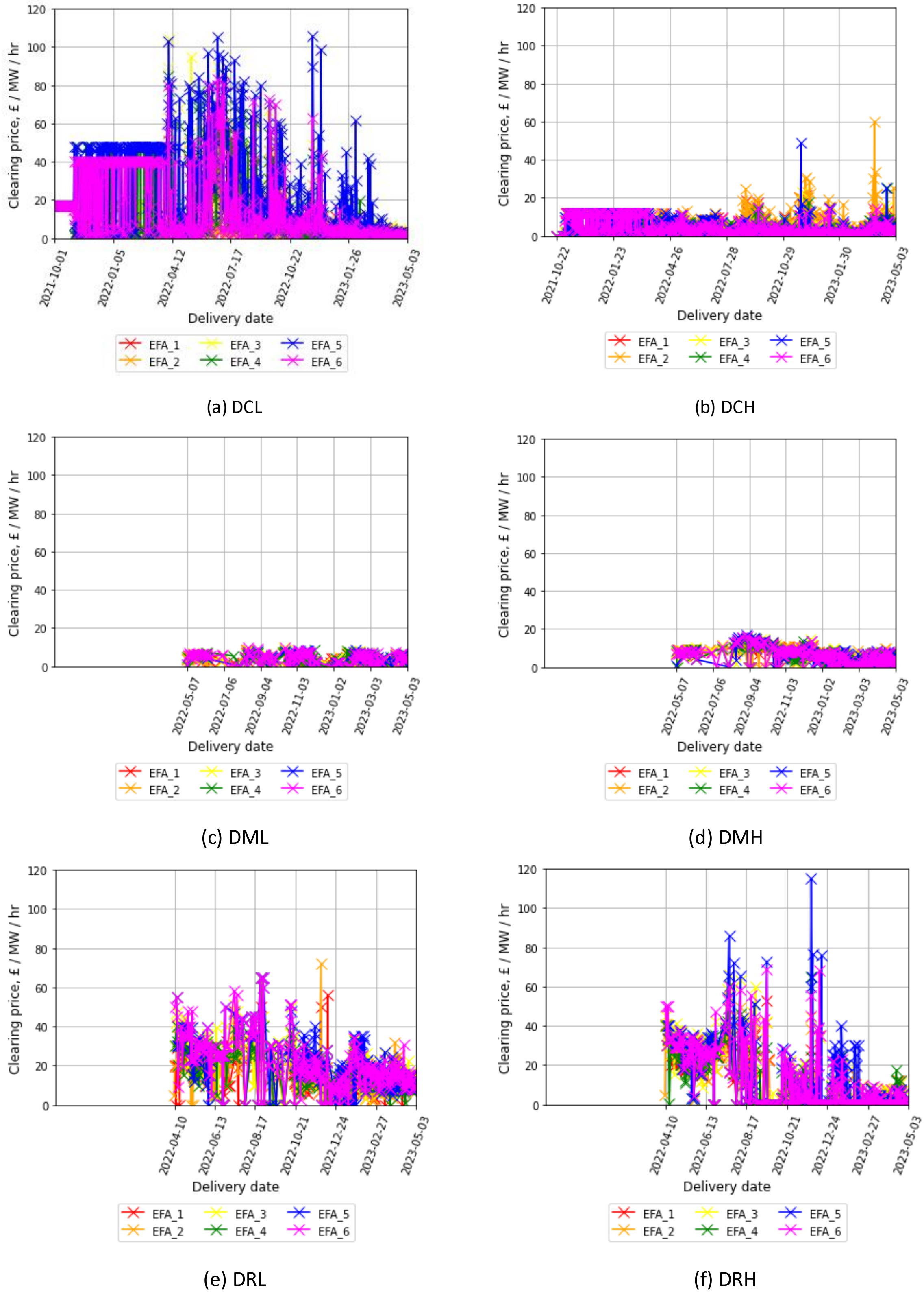
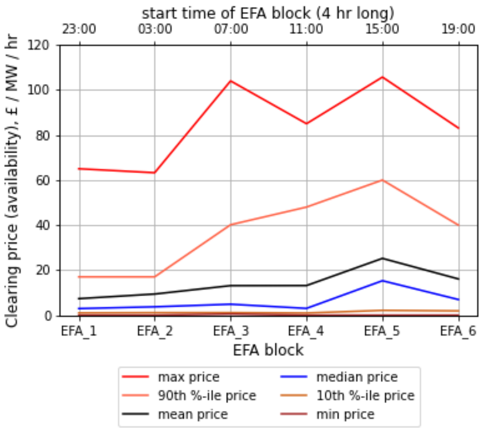
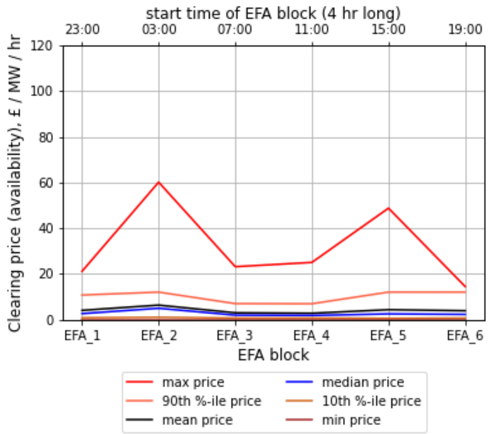


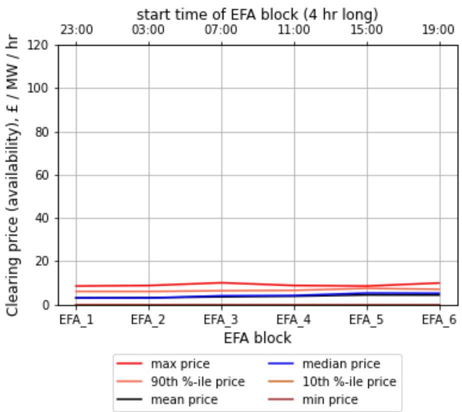
Figure 8 Timeseries of auction clearing prices for DCL, DCH, DML, DMH, DRL, DRH, for each EFA (time of day) block. October 2021 – May 2023. Data from [133]



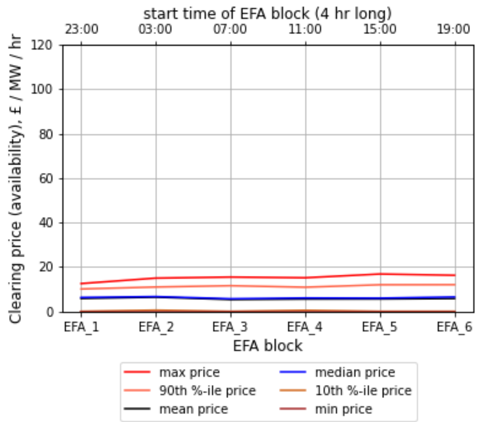
(a) DCL (1 October 2021 to 3 May 2023)



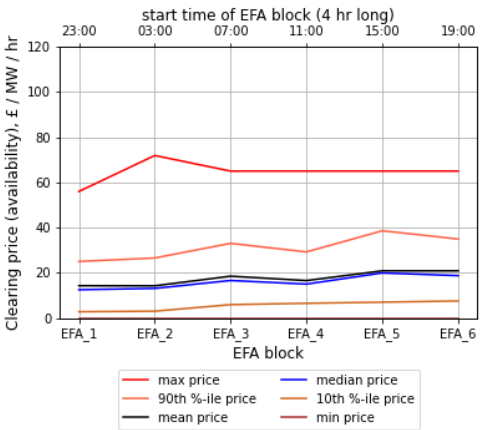
(b) DCH (1 October 2021 to 3 May 2023)



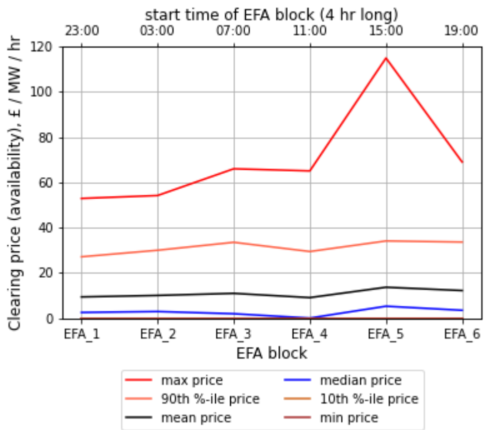
(c) DML (7 May 2022 to 3 May 2023)



(d) DMH (7 May 2022 to 3 May 2023)



(e) DRL (10 April 2022 to 3 May 2023)



(f) DRH (10 April 2022 to 3 May 2023)

Figure 9 Summary stats for auction clearing prices DCL, DCH, DML, DMH, DRL, DRH, October 2021 – May 2023.[23] Data from [133]

[23] All statistics are based on the blocks where orders were executed. For DM and DR, there were numerous days on which some or all blocks were not procured. These figures do not include such blocks in calculations.

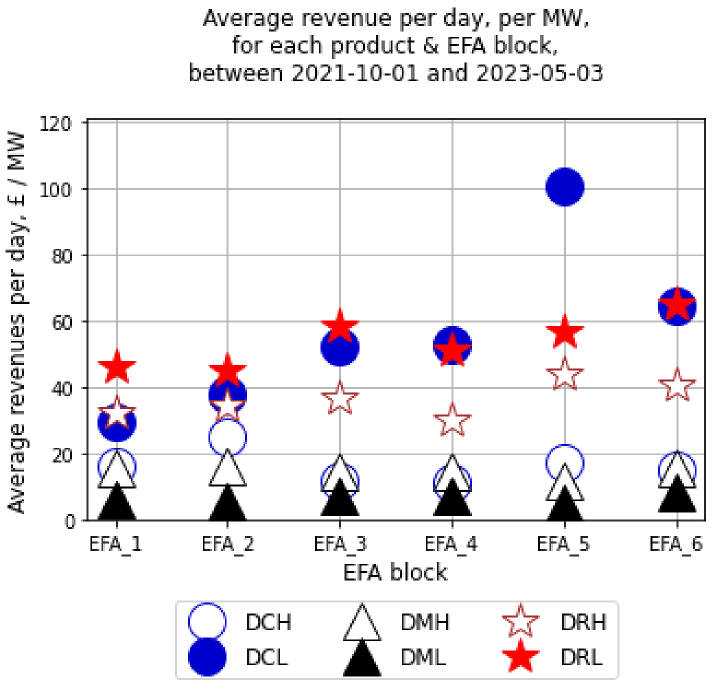


Figure 10 Average[24] daily revenue, split by EFA block, for provision of DC, DM and DR frequency response services, between 1 Oct 2021 (or date of service launch, when later) and 3 May 2023. Data from [133]

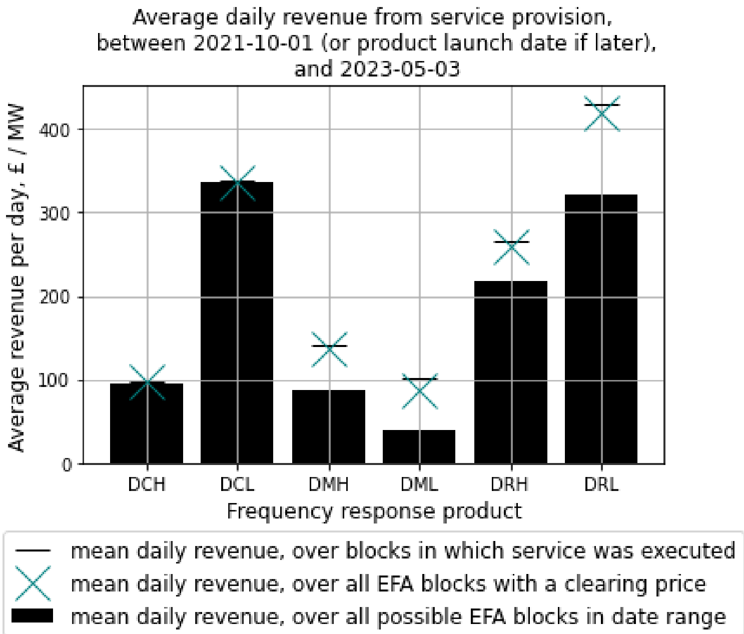


Figure 11 Average daily revenue, total across all EFA blocks, for provision of DC, DM and DR frequency response services, between 1 Oct 2021 (or date of service launch, when later) and 3 May 2023. Data from [133]

[24] Mean daily revenue, based on total revenue, and total number of days in the date range over which service could have been procured. The denominator includes days on which no service was procured.

In Figure 11, the additional mean daily revenue figures, higher for DM and DR occur because on some days the market did not clear (e.g. the ESO chose not to procure some of these services during some EFA blocks on some days); on a few other days, the ESO's data show that market cleared but no blocks were executed: it is unclear why this happened. Excluding the days of no service provision from the calculation of average revenues would result in higher average incomes.

These charts show that frequency response provision was a viable revenue-generating activity for batteries throughout 2022, though potential incomes declined toward the end of the year and remained lower into 2023.

3.2.3.2. Potential revenues from DC/DM/DR frequency response provision during three "case study" time periods in 2022

The following chapter of this thesis explores potential net revenues a battery could accrue by engaging in wholesale trades, during three 5-week case study periods during 2022.

For comparison, the potential revenues a battery could accrue if engaged in frequency response provision during those dates are enumerated below.

The dates are:

- "Summer": 26 May – 29 June 2022, inclusive
- "Autumn": 25 September – 29 October 2022, inclusive
- "Winter": 17 November – 21 December 2022, inclusive

Timeseries of potential revenues for DC, DM and DR, for all the EFA blocks, during each of the three above case study seasons, are shown in Chapter 3 Annex 2.

Figure 12 (a) and (d), and Figure 13 (a), show timeseries clearing prices for the frequency response service *with the highest overall prices*, over the summer, autumn and winter case study periods, respectively. Figure 12 (b) and (e), and Figure 13 (b), show potential average daily revenues for each frequency response product (averaged over the whole of the time interval).

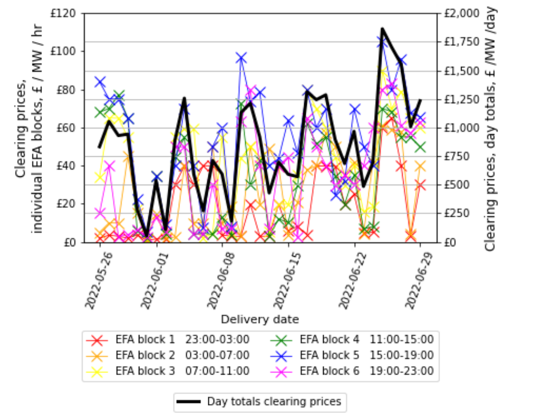
Clearly, average prices over each 5-week case study period mask days and EFA blocks of much higher and lower clearing prices, and blocks of no service procurement, as illustrated in the timeseries charts Figure 12(a), Figure 12(d) and Figure 13(a), with results for all frequency products over the case studies shown in Chapter 3 Annex 2. However, the calculation of average potential revenues per day over the cases study periods for these services is nevertheless useful, to aid comparison of potential revenues with an alternative activity, wholesale trading, over the same case study periods (described in Chapter 4).

Figure 12 (c) and (f), and Figure 13 (c), show average total daily revenues which would be accrued by offering each service for all EFA blocks, for the whole of the summer, autumn and winter case study periods. These values are tabulated in Table 8.

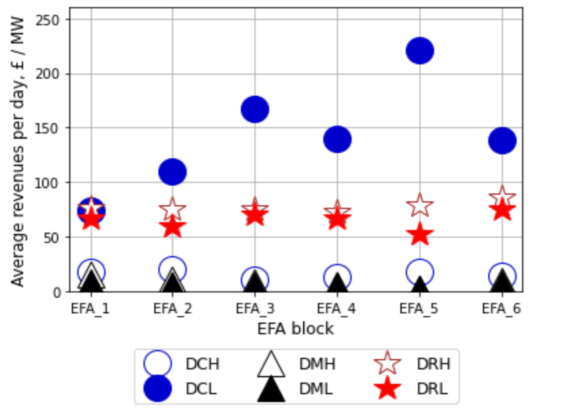
Table 8 Summary of potential revenues from frequency response service provision every day, across all EFA blocks, during "summer", "autumn" and "winter" 2022 case study seasons. Data from [133]

Case study period	Average daily potential revenues, £ / MW / day (averaged over whole time interval)					
	DCL	DCH	DML	DMH	DRL	DRH
Summer	**£848**	*£93*	*£33*	*£51*	£462	£391
Autumn	**£280**	*£59*	*£40*	£109	£240	£108
Winter	£208	£108	*£34*	£134	**£272**	£166
Key:	(green)	**Most lucrative service for that season**				
	(dark yellow)	Second most lucrative service for that season				
	(light yellow)	Next most lucrative service for that season				
	(grey)	*Least lucrative service for that season*				

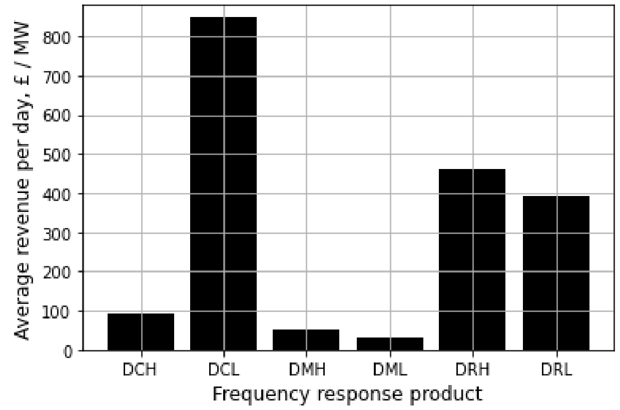
These totals should be regarded as minimum levels of potential revenues. Figure 12 (b) illustrates that in summer, DCL outperformed all other products in terms of revenues for its providers over all EFA blocks. In autumn and especially in winter, however, different frequency products cleared at higher prices over different EFA blocks, on average, as shown in Figure 12 (e) and Figure 13 (b). An astute battery owner could increase income by offering different products at different times of day. Furthermore, prices for all EFA blocks varied considerably from day to day, as illustrated in Chapter 3 Annex 2. Further revenue improvements could be made by changing offerings from day to day, as well as offering different products for different EFA blocks.



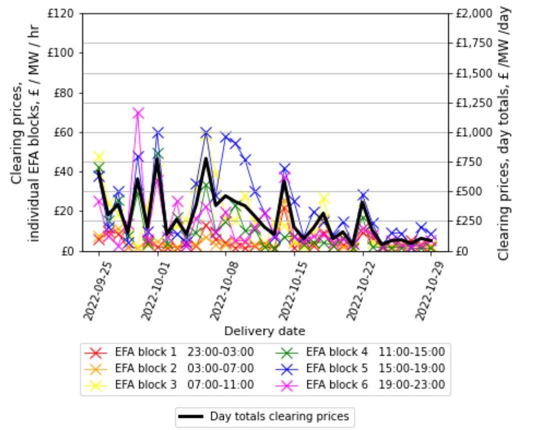
(a) summer case study, timeseries clearing prices for DCL



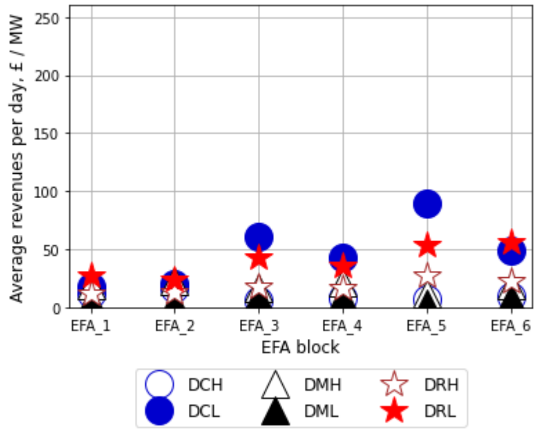
(b) summer case study, average daily revenue for each EFA block



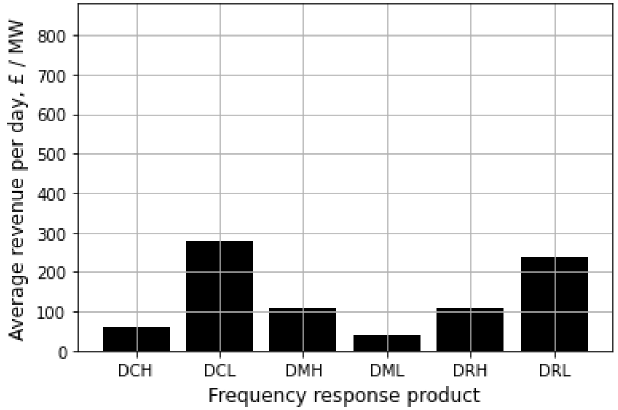
(c) summer case study, average total daily revenue across all EFA blocks



(d) autumn cases study, timeseries clearing prices for DCL

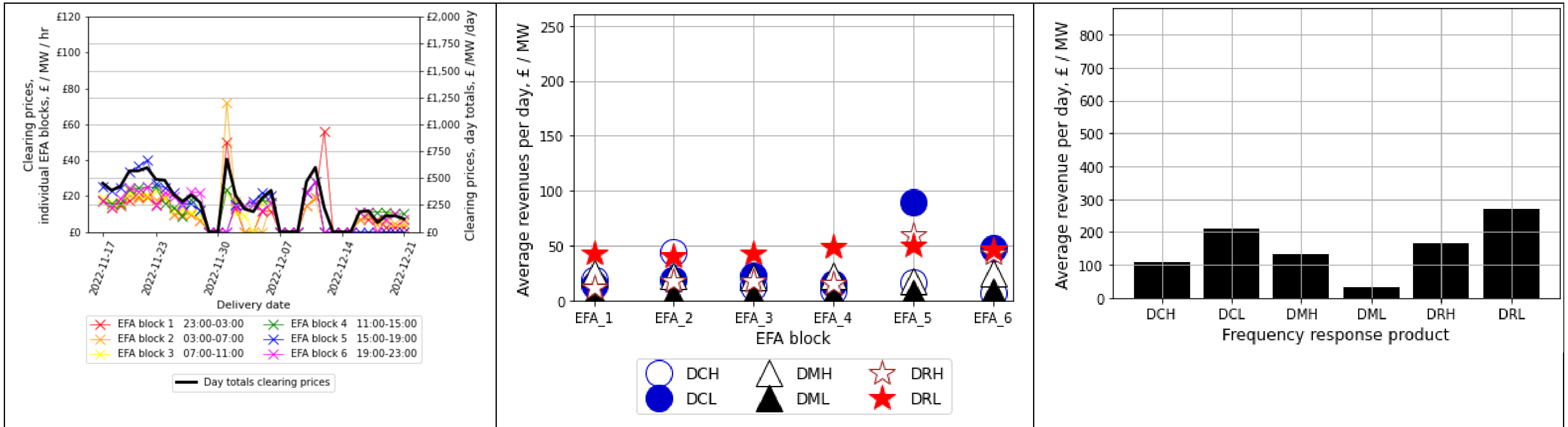


(e) autumn case study, average daily revenue for each EFA block



(f) autumn case study, average total daily revenue across all EFA blocks

Figure 12 Timeseries clearing price of best-performing frequency response product (DC, DM or DR); potential average daily revenues per EFA block from provision of DC, DM and DR per; potential average daily revenues in total across all EFA blocks from DC, DM and DR. For the summer and autumn case study periods. Data from [133]



(a) winter case study, timeseries clearing prices for DRL

(b) winter case study, average daily revenue for each EFA block

(c) winter case study, average total daily revenue across all EFA blocks

Figure 13 Timeseries clearing price of best-performing frequency response product (DC, DM or DR); potential average daily revenues per EFA block from provision of DC, DM and DR per; potential average daily revenues in total across all EFA blocks from DC, DM and DR. For the winter case study period. Data from [133]

A battery *may* be able to offer both high and low services at the same time, particularly for the shorter-duration DC and DM services, if it starts with and can maintain a suitable state of charge. Any such offering would be subject to compliance with the ESO's rules on batteries' state of charge and energy store through the EFA block in 2022 [134]–[136], rules later amended, 2025 rules shown in [137].

These frequency response products' rules also limited rates and ramp rates of recharging after any service delivery, to avoid any further system disturbance in the aftermath of an initial event requiring delivery of response services. Such restrictions may complicate simultaneous high and low service provision. A 2-hour battery would not be able to offer simultaneously high and low DR at full capacity (i.e. maximum MW), because it would be required to have "reserved capacity" to offer provision for over 1 hour in both directions, and also to slowly recharge [137]. Batteries can offer services at less-than-full capacity, though offerings must be in whole numbers of MW.

3.2.3.3. Participation of batteries in frequency response services

The ESO's Market Data for the DC, DM and DR services list the names of the owner, and an identifier for each unit [132].

Unfortunately, this dataset does not list the technology type of participants, though in some cases the owner's name strongly suggests energy storage; some owners are generic energy service providers or aggregators. This dataset lists around 72 unique identifiers, assumed to be unique service providers[25].

However, these 72 unique identifiers / providers include 19 identifiers which also appear on the list of batteries engaged in a completely different pair of activities, the *Balancing Mechanism and Wholesale trades*, activities which are described in Section 3.3. The latter list does state technology type of participants. There were 23 batteries which engaged in at least one wholesale trading or Balancing Mechanism action during 2022 (with one additional battery which first offered frequency response services in early 2023), of which 19 had an identifier which is also listed in the Market Data for DC, DM and DR. It is assumed these same identifiers, on the two lists of different activities, refer to the same battery units.

[25] Identifiers which appeared to be spelling variations of other listed units were not counted separately, neither were entries which appeared to be aggregators or other provider types.

Using this assumption, at least 19 battery units, but potentially up to around 70 battery units, provided "end-state" frequency response services (i.e. one or more of DC, DM and/ or DR) during 2022[26]. Of these, 19 also engaged in wholesale trades and / or Balancing Mechanism activity. Most batteries which engaged in both activities started trading activities and frequency response services within a month of each other. Of the 4 batteries which participated in wholesale trades but did not offer frequency response services, all started trading (or in one case, trading regularly) at the end of the year, in December. Batteries' details are shown in Chapter 3 Annex 3.

3.2.4. Reserve services

Provision of Reserve services to the ESO is a further potential revenue stream for batteries. Reserve services provide Frequency Restoration Reserves [138] to the ESO, defined in the ESO's Grid Code as "*in the context of Balancing Services, [Frequency Restoration Reserves are] the Active Power reserves available to restore System Frequency to the nominal Frequency*" [117]. Reserve services are slower to respond than frequency response services, and are normally required to extend provision for longer.

Of most interest to batteries would be a fast-acting reserve service, such as "Fast Reserve", which requires response within 2 minutes, continuing for 15 minutes [139]. Market Information Reports for Fast Reserve from 2020-2021 show much lower prices than for frequency response services, very rarely exceeding £200/MWh [140]. However, no market reports for Fast Reserve are available on the ESO's website beyond June 2021.

Longer-duration reserve service Short-Term Operating Reserve (STOR) could have been offered by participants able to deliver for periods of 2 hours or more, which would be open to many batteries, though most service delivery times during 2022-23 required longer delivery times, of up to 7 hours, which are out-of-reach for short-duration batteries [141]. Short duration batteries therefore could have engaged in this service, but only as an occasional or supplementary revenue stream.

NGESO's reserves portfolio has been under review since 2022 [142], [143].

- A faster-acting reserve service not available during 2022, "Quick Reserve" [144], has been in preparation during 2024 with its launch imminent at time of writing (late

[26] Additional batteries may potentially participate via an aggregator

2024). This and potentially other future reserve services could be an additional revenue stream of interest to batteries.

- A replacement for STOR, "Slow Reserve", is also under development [145], with suggested minimum delivery periods of 2 hours : this service may also be an option for batteries and other storage assets, especially those of longer duration.
- The ESO propose to introduce a new reserve service, "Balancing reserve" [146], to allow more procurement day ahead, intended to be allow cheaper service procurement than using the Balancing Mechanism in-day (described in the following section). Few details are available.

In short, reserve services are a potential income stream, though they can also be provided by other technologies with slower activation times and longer delivery times than batteries, which could be expected to drive down prices. In some cases, required delivery times exceed capabilities of short-duration batteries.

During the year of interest, 2022, reserve services were under review, and little market information is available.

3.3. Balancing Mechanism and Wholesale Trades

3.3.1. Overview

Electricity is traded between generators and entities which use energy (Suppliers and large demand users) largely in bilateral trades, with "Spot market" platforms allowing further day-ahead and in-day trades.

Transmission-connected generators, Suppliers, and certain other major entities are required to register with both the ESO and the trades administrator Elexon as *Balancing Mechanism Units* (BMUs). BMUs are required to inform the ESO of their intended output (or consumption) of electricity for each half hour Settlement Period, in a Final Physical Notification (FPN), prior to "gate closure" an hour ahead of delivery (or consumption).

The ESO uses the Balancing Mechanism (BM) as a tool to manage any imbalance between generation and demand, and any other system operability constraints. BMUs are required to state the price at which they would increase output of electricity (or reduce consumption), in an *Offer*, or decrease generation (or increase consumption), in a *Bid.* In the time between gate closure and real time, the ESO accepts some of the Bids and / or Offers, as necessary for system operation, by issuing Bid Offer Acceptance notices (BOAs) to the selected BMUs [147]–[149].

Traditionally, BM participants were larger transmission-connected and larger distribution-connected generators, Suppliers[27], and certain other entities, including financial organisations. However, the ESO and other European TOs have taken steps to enable wider access to the BM, and participants sized from 1 MW can opt to participate. Participation requires registrations with the ESO and with the trades administrator Elexon, testing, and communications and monitoring infrastructure with the ESO and Elexon. Small units may register via an *aggregator* or a *virtual lead party*, as described in [150]–[152].

3.3.2. Potential revenues

Potential revenues from wholesale trades during selected periods of 2022 are enumerated in the following chapter.

Potential revenues from Balancing actions have not been enumerated. It is NGESO, not an individual provider, which decides which BM participant to instruct to deliver an offer or bid, so estimates of future incomes for any single service provider would be subject to significant uncertainty. However, this would be a useful avenue of further work.

Transmission Constraints services

As described above in Section 3.3.1, the ESO uses the BM to manage a range of system operability issues and imbalances between generation and demand.

In recent years, as more wind generation is deployed in Scotland, during windy weather, total inflexible generation significantly exceeds both demand in Scotland and also transmission network's capacity to export excess generation to larger demand centres further south in GB, particularly across the "B6" transmission boundary[28] which delimits the transmission system in Scotland from that in England and Wales. (This thesis further explores implications of this transmission constraint in Chapter 5.)

The BM is used to manage this constraint. At times of high wind, generators – normally wind – in Scotland (north of the constraint) are instructed to reduce output, while thermal generators

[27] *Suppliers* in the GB system are the entities which perform the retail function of electricity, i.e. purchase electricity in wholesale markets, and contract to supply residential and non-residential end-users of electricity [283]

[28] As described, for example, in the ESO's Electricity Ten Year Statement (ETYS). ETYS 2024 is found here: [274]

in England (south of the constraint) are instructed to increase output. Both the turning down of turning up of generation in different places add to constraint costs, costs which dominate overall balancing costs, and which have doubled since 2018/2019 due to both higher volumes and higher wholesale electricity prices, as illustrated in Figure 14.

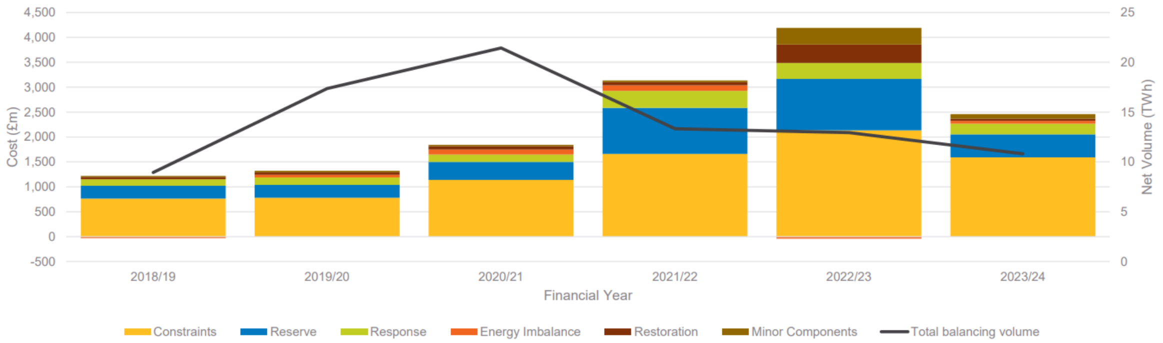


Figure 14 Outturn balancing costs and volumes 2018/19 to 2023/24. Reproduced from NESO [153]

In [153], [154], the ESO states its expectation that high constraint costs will continue for some years because of the time lag between installation of greater wind generation capacity in (and offshore of) Scotland, and of additional transmission network capacity across this constraint.

Deployment of batteries would be expected to reduce constraint costs, as the ESO would have greater choice of which assets to constraint on or off and could choose lower cost options, provided compatible with any other operability constraints. Batteries located in Scotland, north of the major constraints, would be expected to propose bids (generation turn-down or demand turn-up) of lower cost than most wind generators which provide this service (most of which charge to turn down, to compensate for the loss of generation-pegged subsidy). An industry report from 2024 [155] finds that some batteries BMUs in Scotland are indeed being instructed by the ESO to provide BM bids (presumably at lower cost than other providers). However concern has been raised that some batteries are being paid for managing a constraint that is partly of their own making [156], a criticism that could perhaps be made of other generators. The same industry report found that batteries, anywhere in GB, as of 2024, were very rarely used to provide BM offers (generation turn-up / demand turn-down). This is clearly an evolving area.

[153] describes the ESO's actions, which include a suite of additional planned network connections, over the coming years, and *constraint management markets,* such as a "Grid booster", described in service [157], in which batteries or other energy storage assets near to a

transmission constraint boundary (the “B6” boundary being of most interest), may in future provide contingency or a post-fault service .

Potential revenues are not considered here, but could be part of a storage asset’s business case, if such services would be paid well enough, or be required for long enough, for a storage asset to construct a viable business case.

3.3.3. Wholesale trading and BM activity among grid-connected batteries in GB

Balancing Mechanism data for 2022 list 40 battery BMUs within GB, of which 23 had activity (wholesale trades and or BM trades) during that year. Of these, only 7 had any activity in January 2022; the others commenced activity later in the year, with 3 not commencing activity until December.

The batteries are listed in Chapter 3 Annex 3, together with dates of first frequency response, FPN and BM activities. Chapter 3 Annex 4 displays timeseries plots of FPN and BM activity for all batteries active during 2022. Chapter 3 Annex 5 summarises battery activity (wholesale trades, provision of DC/ DM / DR frequency response services, and BM trades, as a percentage of FPNs) during three case study seasons in 2022, which are described in greater detail in the following chapter. Annexes 4 and 5 shows that almost all batteries which participated in wholesale trades also engaged in at least one balancing action. However, all providers, the volume of wholesale trades far exceeded that of balancing actions, though for a few batteries, there were shorter periods during which balancing actions were significant compared to other activity.

One immediate observation is that many batteries had very different patterns of activity at different times. Many operated at capacities (MW) much below their maximum (taken to be the larger of the highest export and the highest import FPN occurring during 2022) for significant periods of time. This may be explained by batteries “stacking”, i.e. using parts of their capacity for different activities, as described in Chapter 2. Several batteries[29] operated with very small FPNs, an order of magnitude lower than their maximum FPNs, for extended periods. This activity could be accompanying frequency response service delivery, by

[29] Examples include Port of Tyne, Roosecote, Kemsley, Pen y Cymoedd, and the two West Burton B batteries. Timeseries of all batteries are shown in Annex 4.

performing slow adjustments to or maintenance of their State of Charge, as required by NGESO's rules for frequency response providers. In the case of new batteries, very low-power activity could be part of a commissioning phase. Several batteries had extended periods of only or predominantly engaging in either imports or exports, even including BM trades, which is surprising, but could be recovery from the delivery of frequency response services. Some differences in activity between batteries may be explained by the degree of access that they have to information and forecasts, and the quality of such data. Differing access to ancillary services markets or various trading platforms (all of which have their own registration and approval processes) may also explain some differences in activity over time, and between batteries, as could their owners' business models, preferences and appetite for risk. Operational constraints, such as specific cycling requirements or limitations to maintain asset health and / or comply with warranty conditions, may also govern batteries' activity. In short, there is significant diversity of battery activity between batteries, and in some cases between activity of the same battery at different times. It is likely they are engaging in different activities, including wholesale trades, but some features of their activity are hard to surmise.

3.4. Capacity Market

3.4.1. Introduction

The Capacity Market is a UK Government mechanism to ensure electricity system security in the event of low generation conditions [13], [158]. Providers, which could be schedulable generators or demands, are selected at auctions, and are contracted to deliver generation or demand reduction if required. Providers receive a steady income, but would face penalties for any failure to deliver if required.

3.4.2. Requirements

Providers, (termed *Capacity Market Units*, CMUs), are required to remain ready to deliver capacity as required. In the event of expected generation falling to within 500 MW of expected demand, the ESO would issue a Capacity Market Notice. A CMU is expected to deliver its de-rated capacity, 4 hours after the ESO issues a Capacity Market Notice, for as long as the system stress event lasts.

Definitions of a *system stress event*, *capacity market system stress event* and other relevant terms are covered in [159] and described in Chapter 3 Annex 6. NGESO determines retrospectively whether or not a Capacity Market System stress event occurred.

To date, there have not been any Capacity Market events. Capacity Market Notices have been issued, but withdrawn within the four hours between notice issue and required delivery. Details of a recent example of such an event are included in Box 1.

Box 1: Example of a recent Capacity Market notice

Capacity Market Notice: 8 January 2025

In the most recent example of a Capacity Market Notice, tight *margins* for the evening peak in demand on 8 January were identified several days beforehand, as described by NESO in [287]. (The *margins* refer to the capacity of additional generation available and not despatched, and which might, potentially, be needed in the event of an outage.)

Despite NESO actions of rescheduling planned transmission works to allow greater generation capacity, on the morning of 8 January, output from wind and a thermal generator were lower than expected, and the forecast for the evening peak demand was rising. With these in-day changes reducing already-tight electricity system margins, a Capacity Market Notice, and also an Electricity Market Notice, were issued, around midday, for the forthcoming evening peak demand period.

NESO then arranged interconnector imports, additional generation, and demand flexibility services delivery, to cover the high-demand evening peak. These actions increased the margin on the electricity system, and both Capacity Market Notice and Electricity Market Notice were cancelled in the afternoon, prior to the high demand period, and prior to the expected Capacity Market event period. Thus, no Capacity Market actions from providers were required.

CMUs face penalties for under-delivery during a Capacity Market event, and there may be rewards for over-delivery. Financial rewards from arbitrage would have to be extremely good to make a first penalty worth incurring. However, if multiple events happened within a month, the monthly penalty for a CMU is capped at twice its monthly payment, so any failure to deliver on additional CM events within a month would result in diminishing penalties.

Any CMUs providing ancillary services (e.g. frequency response or reserve) to the ESO during a system stress event, or responding to a Balancing Mechanism instruction, are exempt from the CM requirement to deliver additional generation or demand reduction.

All rewards, and the continuation of CM registration, are subject to monitoring, information provision and other actions stipulated by NGESO.

3.4.3. Auction results

Prices are determined at auctions, primarily T-4 (nominally 4 years ahead) and T-1 (nominally 1 year ahead). Each auction has a single clearing price applicable to all successful participants. A technology-specific de-rating factor is applied to all payments, taking into account likelihood of non-delivery, with the greatest de-ratings applied to very short-duration storage assets and some weather-dependent renewable generators [160], [161]. Results of CM auctions for delivery in year 2022/23 are tabulated in Table 9. Results of auctions for delivery the following year, and results of auctions held during 2022 and 2023, are tabulated in Chapter 3 Annex 7 for reference.

A 2-hour battery contracted to deliver in the CM during 2022/23 would earn payments of around £10 / MW/day in the 2019 T-3 auction [160], [162], and around £100 / MW/day in the 2021 T-1 auction [161], [163], as shown in Table 9. Incomes varied between auctions, with respective payments for delivery the following year being £20 / MW/day (T-4) [160], [164] and £60 / MW/day (T-1) [161], [165]; de-rated prices for a 2-hour battery, for auctions held during 2022 and 2023 ranged from £33 / MW/day [161], [166] to £104 /MW/ day [161], [163], as tabulated in Chapter 3 Annex 7. In most of the auctions reported, incomes for 1-hour batteries would be approximately half of those for 2-hour batteries; incomes for 4-hour batteries would be approximately 150% of those of 2-hour batteries [160], [161].

Table 9 Capacity Market: Auction results, de-rating factors and revenues for storage participants [160]–[163]. Delivery year 2022/23

Auction	2019 T-3 2022/23				2021 T-1 2022/23			
Auction held	Feb 2020				Feb 2022			
Delivery year	2022/23				2022/23			
Storage duration	De-rating factor	Auction clearing price, £/kW/yr	Revenue, £/MW/yr [30]	**Revenue, £/MW /day** [31]	De-rating factor	Auction clearing price, £/kW/yr	Revenue, £/MW/yr [30]	**Revenue, £/MW /day** [31]
Storage – 1 hr	21.36%	£6.44	£1,376	**£3.77**	25.87%	£75	£19,403	**£53.16**
Storage – 2 hr	42.53%	£6.44	£2,739	**£7.50**	50.63%	£75	£37,973	**£104.03**
Storage – 4 hr	67.04%	£6.44	£4,317	**£11.83**	74.84%	£75	£56,130	**£153.78**

3.4.4. Conclusion on viability of Capacity Market as an activity for batteries

The Capacity Market is a further potential revenue stream available to batteries and other storage providers. Revenues are relatively small, but nevertheless appealing for several reasons. Contracts are for at least a year and bring in monthly payments. Payments can be stacked with other revenue streams. Requirements on participants do not appear excessively onerous or expensive. Indeed, a battery or other provider may not have to do much other than actions it would be incentivised to do by expected high wholesale prices during a system stress event.

Looking forward, reform to the Capacity Market is within the scope of REMA [24], so changes to rules and requirements may be forthcoming.

[30] Annual revenues (£/MW/year) were calculated by multiplying the £/kW/year clearing price (from the auction results) by the technology-specific de-rating factor (also in the auction results) and then by 1000 (to convert from kW to MW).

[31] Projected daily revenues were calculated by dividing annual revenues by 365.

3.5. Use of System Network charges: avoidance and credits

A further potential set of revenue streams for a battery would be to reduce charges, or gain credits, relating to the Use of System charges (or credits) for use of both Transmission and Distribution networks, charges which most electricity system users pay in their electricity bills. These charges are known as Transmission Network Use of System (TNUoS) and Distribution network Use of System (DUoS) charges, respectively.

One approach would be to reduce the charges a large electricity consumer would incur, by reducing the demand through its MPAN during periods when high network charges apply. This approach would be applicable to batteries connected "behind the meter" of a large consumer. A battery or other schedulable energy asset could potentially reduce both TNUoS and DUoS charges.

Alternatively, a stand-alone battery (or schedulable generator) could accrue DUoS and potentially TNUoS credits for exports during times of high demand-driven network congestion.

Potential revenues for a battery are summarised below. Such approaches have been of among the revenue streams of interest to storage and other flexible energy resources [167].

3.5.1. TNUoS charges and credits

All users of the electricity network, whether Transmission or Distribution-connected, are liable for Transmission Network Use of System (TNUoS) charges. Transmission connected batteries would normally be liable for generation TNUoS charges (or credits) [168], which depend entirely on location, and have no time-of-use element. However, distribution-connected batteries may be able to access TNUoS credits, depending on contract and connection type.

3.5.1.1. "Triad avoidance"

This service could be an option for a battery connected "behind the meter" of a large electricity consumer.

Prior to financial year 2023/24, for half-hourly metered consumers, the entire charging base for TNUoS charges on half-hourly-metered customers was their consumption during "Triads" settlement periods. The "Triads " are the three settlement periods of highest system demand, occurring during the winter months (November to February inclusive) of a financial year, and separated by at least 10 clear days [169]. Triad periods are determined retrospectively.

The charges vary with location, with lowest charges in Northern Scotland, and the highest in the South West England, as shown in Table 10.

A major reform of network charges (the Targeted Charging Review [99]) changed the basis for TNUoS revenue collection. From 2023/24 onwards, the bulk of TNUoS charges for demand users (i.e. electricity consumers) are collected via standing charges. “Triads” do remain, but as an additional and much smaller charge, applicable in southern parts of Britain only, as shown in Table 10 for year 2023/24 and 2024/25.

Thus, in 2022/23, a battery which facilitated reduction of average Triad demand by 1 MW, would have saved an industrial consumer between around £30,000 (in Scotland) and £45,000 - £65,000 (in England and Wales) over that financial year. This revenue figure does not include the cost of the energy purchase. However, energy prices are likely to be high at times of high system demand, so purchasing energy in advance, storing it for use during possible “Triad” periods is very likely to bring additional financial benefit. Estimated incomes from wholesale trade in electricity are discussed in Chapter 4.

Triad periods by definition occur between November and February, inclusive. To date, Triad periods have fallen during weekdays, and not during holidays. This leaves approximately 78 days over the winter during which they could occur. They have fallen during settlement periods 34-37 (i.e. between 16:30 and 18:30) i.e. during a 2 hour period [170], a timescale very suitable for a short-duration battery to act in.

$$No\_winterdays\_total = 120 \tag{3.1}$$

$$No\_winterdays\_not\_holidays = (No\_winterdays\_total - 10days) \tag{3.2}$$

$$No\_winter\_weekdays = \left((No\_winterdays\_not\_holidays) * \frac{5}{7} \right) = 78 \tag{3.3}$$

If a 1 MW battery was to be active on all of the 78 weekdays over the winter during which a Triad event may be declared, the average income of TNUoS avoidance, per day of activity, would be as shown below:

$$Average\ daily\ income_{Triad\_avoidance}\ \left(\frac{£}{day}\right) = \frac{tariff\left(\frac{£}{kW}\right) * 1000\left(\frac{kW}{MW}\right)}{78\ (days)} \tag{3.4}$$

Average daily revenues for a battery owner, based on triad avoidance over 78 days a year, are shown in Table 10.

An astute battery owner, able to predict days which have greater or lesser likelihood of Triad occurrence, may be able to be active on fewer days (those with greatest likelihood of a Triad event), and thus achieve better per-day revenue.

Any triad avoidance activity would also help reduce DUoS charges levied on a major electricity consumer, as described below in Section 3.5.2.

Table 10 Annual TNUoS HH demand tariffs, and estimated average daily TNUoS avoidance revenue for a 1MW battery, based on 78 days activity/year, 2022/23-2024/25, selected GB TNUoS zones

TNUoS Zone	Zone name	TNUoS tariffs, £ / kW demand tariff for half-hourly metered customers, applied to average Triad demand			Average daily revenue in Triad avoidance, for a 1 MW battery, averaged over 78 days / year		
		2022/23 [171]	2023/24 [172]	2024/25 [173]	2022/23	2023/24	2024/25
1	Northern Scotland	£27.45	£0	£0	£352	£0	£0
2	Southern Scotland	£35.47	£0	£0	£455	£0	£0
3	Northern	£44.68	£0	£0	£573	£0	£0
8	Midlands	£57.19	£3.05	£2.37	£733	£39	£30
12	London	£63.69	£4.37	£5.73	£817	£56	£74
14	South Western	£63.75	£7.65	£8.20	£817	£98	£105

3.5.1.2. Embedded Export TNUoS credits

Embedded Export Tariffs (EETs) are a form of TNUoS credit, available for some distribution-connected sites, depending upon contract type, for delivery of net exports during "Triad" settlement periods. This is a potential revenue stream for a stand-alone battery located in the English Midlands or South, or South Wales.

Table 11 shows that a User eligible for EETs, and which delivers 1 MW for all of the Triad Settlement Periods, would accrue an annual credit of £5,000 in the Midlands (2024/25) and just over twice that if located in the South Western region.

Table 11 Annual TNUoS Embedded Export Tariffs

TNUoS Zone	Zone name	TNUoS Embedded Export Tariffs, £ / kW (applied to average Triad export)		
		2022/23 [171]	2023/24 [172]	2024/25 [173]
1	Northern Scotland	£0	£0	£0
2	Southern Scotland	£0	£0	£0
3	Northern	£0	£0	£0
8	Midlands	£2.68	£5.59	£5.09
12	London	£9.19	£6.92	£8.44
14	South Western	£9.24	£10.19	£10.91

Using similar working to that in Section 3.5.1.1, if considering exports are necessary for 78 days in the year to cover possible "Triad" days, then the average credit per day would range from £0 (in the north) to around £100 / day (London) and £120 - £140 / day in the highest tariff zone, South Western, during 2022/23 to 2024 /25.

3.5.2. DUoS charges and credits

DUoS charges are collected via a combination of standing charges and time-of-use (TOU) tariffs. Each DNO region has its own set of charges, within which different charges apply depending upon the voltage of connection, and type of user. DUoS charges for HV and LV connected users are calculated by Common Distribution Charging Methodology (CDCM), as set out by DCUSA [62]. These charges are all generic to all similar users connected in the same DNO region. Negative charges, i.e. credits, are awarded to generators. DUoS charges for EHV-connected users are calculated by either Long Run Incremental Cost (LRIC) or Forward Cost Pricing (FCP) methodologies, depending on DNO region, as set out by DCUSA in [174], [175]. EHV DUoS charges are all specific to individual sites. DUoS charges are currently under review [176].

3.5.2.1. HV-connected sites

For HV-connected users, the TOU tariffs are in a format of "red band", "amber band" and "green band" tariffs, corresponding to times of high, medium and low import flows on networks.

DNOs define the timings of the various bands, which are set over a year in advance, and do not vary by time of year. All 14 DNO regions have a "red band" occurring during late afternoon and early evening on weekdays; London alone has an additional red band period around midday[32]. The tariffs themselves vary between DNOs, and by voltage of connection and type of user. For an HV-connected large demand site ("band 4"), red band DUoS demand charges are typically around a few pence per kWh. For a stand-alone battery or other generator, or one at a site which can export during red-band times, the red band DUoS credits are slightly higher than the "avoided costs".

Two scenarios are considered here. The first scenario considers a battery located "behind the meter" at the site of a large demand user. This battery's exports during "red band" times reduce the demand site's consumption, and so reduce its red band DUoS charges. In the second scenario, the battery is stand-alone, or part of a site which has net exports during red band periods. This battery (or exporting site) receives DUoS credits for its exports during red band periods.

Taking examples from two DNO regions (Southern Scotland, and London), and two years (2022/23, and 2024/25), red-band demand tariffs and export credits are tabulated in Table 12. This table further enumerates possible DUoS red band "charge avoidance" and "credit" that a 1 MW battery could potentially earn, in £ / day, if exporting throughout the duration of red band periods.

Overall, financial rewards of up to £100 / day during weekdays could be earned through DUoS red-band avoidance, and slightly more from DUoS red band exports. In the case of London, rewards of up to around £200 / day (2024/25 only) would be possible if a battery could deliver twice in a day.

These rewards would be in addition to any TNUoS Triad avoidance benefit, and any financial benefit from purchase of energy at a time of day when price is lower.

[32] In London DNO region, there are two 3-hour long red band periods on weekdays. The time gap between these periods is 2 hours, during which a battery could potentially partially recharge.

Table 12 DUoS "red band" demand tariffs, export credit tariffs, and potential cost savings & incomes from a 1 MW battery. Southern Scotland and London, 2022/23 and 2024/25. (London figures assume site is demand band 4). Tariffs listed at [177]–[180]

Tariffs and potential charges avoidance / credits	2022/23		2024/25	
	Southern Scotland	London	Southern Scotland	London
Imports				
Red Band import tariff, p/kWh	3.029p	1.954p	3.935p	3.318p
Imports charges, £/MWh	£30.29	£19.54	£39.35	£33.18
Import charges £/MW over 3 hour Red Band (Potential £/day saving)	**£90.87**	**£58.62**	**£118.05**	**£99.54**
Import charges £/MW over two 3 hour Red Band periods, London only (Potential £/day saving)	n/a	£117.24	n/a	£199.08
Exports				
Red band export credit tariff, p/kWh	3.601	2.954	4.687	3.787
Export credits, £/MWh	£36.01	£29.54	£46.87	£37.87
Export credits £/MW for delivery over 3-hour Red Band period (Potential £/day income)	**£108.03**	**£88.62**	**£140.61**	**£113.61**
Export credits £/MW over two 3-hour Red Band periods, London only (Potential £/day income)	n/a	£177.24	n/a	£227.22

3.5.2.2. EHV-connected sites

EHV[33]-connected customers have bespoke tariffs, based upon the effect of the site's imports and exports would have on EHV network flows, and the expected number of years before network reinforcement would be required, as set out by DCUSA in [174], [175].

DNOs define a "super red band" time, during which high charges may apply to EHV-connectees. The "super red band" time is the same or close to the time of "red band" charges that apply to HV and LV connected customers.

EHV DUoS charges for demand users are generally considerably lower than those borne by HV-connected customers. In the two regions examined, the EHV super red band charges applied to most demand customers are minimal (< 0.2 pence / kWh) or zero. Some EHV generation sites are awarded credits for exports during Super Red Band periods, though for the majority of sites these credits are zero. The ranges of Super Red Band demand tariffs and export credits

[33] Extra-High Voltage, being a nominal voltage of more than 22kV [284] (within Distribution, not Transmission, networks)

for EHV customers in London and Southern Scotland, in years 2022/23 and 2024/25 are tabulated Table 13, as examples.

Table 13 Range of EHV site-specific "Super Red Band" DUoS import tariffs, export credits, and potential daily incomes for a 1MW battery. S. Scotland and London, 2022/23 and 2024/25. Tariffs listed at [177]–[180]

EHV Super Red Band tariffs for imports and credits for exports, and potential daily charges avoidance & credits	Range	2022/23		2024/25	
		Southern Scotland	London	Southern Scotland	London
Imports					
Super Red Band import tariff, p/kWh	Lowest	0p	0p	0p	0p
	Highest	0.2p	4p	2.863p	1.04p
Number of sites with import tariffs > 1p/kWh	-	0	2	2	1
Imports charges, £/MWh	Lowest	£0	£0	£0	£0
	Highest	£2.00	£40.00	£28.63	£10.40
Import charges £/MW over 3 hour Super Red Band (Potential £/day saving)	Lowest	**£0**	**£0**	**£0**	**£0**
	Highest	**£6.00**	**£120.00**	**£85.89**	**£31.20**
Import charges £/MW over two 3 hour Super Red Band periods, London only. (Potential £/day saving)	Lowest	n/a	£0	n/a	£0
	Highest	n/a	£240.00	n/a	£62.40
Exports					
Super red band export credit tariff, p/kWh	Lowest	0p	0p	0p	0p
	Highest	1.274	0.06	4.907	0.105
Number of sites with export credit tariffs > 1p/kWh		1	0	3	0
Export credits, £/MWh	Lowest	£0	£0	£0	£0
	Highest	£12.74	£0.60	£49.07	£1.05
Export credits £/MW for delivery over 3-hour Super Red Band period (Potential £/day income)	Lowest	**£0**	**£0**	**£0**	**£0**
	Highest	**£38.22**	**£1.80**	**£147.21**	**£3.15**
Export credits £/MW over two 3-hour Super Red Band periods, London only (Potential £/day income)	Lowest	n/a	£0	n/a	£0
	Highest	n/a	£3.60	n/a	£6.30

Thus, with few exceptions, an EHV-connected battery, whether on a demand-site or stand-alone, has much less scope than a battery connected at HV level, for accruing significant revenue through DUoS charges avoidance, or DUoS generation credits, than at HV level. However, for a small number of sites, daily incomes could exceed £100 for a 1 MW battery.

3.6. DSO Flexibility Services

3.6.1. Definitions of "DNO" and "DSO"

The energy networks' trade association the Energy Networks Association (the ENA) wrote in [181]: *"Distribution Network Operators (DNOs) are regulated entities that own and operate electricity distribution networks over a defined geographic area. Historically these networks have been passive in nature, but with increasing volumes of [Distributed Energy resources, (DER)] they are becoming increasingly active. This together with smart grid technologies is creating opportunities for DNOs to realise consumer value and develop SO functions and become a Distribution System Operator (DSO)."*

In [182], the ENA defines DNOs as follows:

"Distribution Network Operators (DNOs) own, operate and maintain the distribution networks. They do not sell electricity to consumers, this is done by the electricity suppliers. There are 14 licensed DNOs in Britain, and each is responsible for a regional distribution services area."

A Distribution *System* Operator (DSO) role is as an evolution of the DNO role, in increasingly active distribution networks. In the above document, the ENA defines a DSO as follows:

"A Distribution System Operator (DSO) has a role to monitor, control and actively manage the power flows on the distribution system to maintain a safe, secure and reliable electricity supply."

"As a neutral facilitator of an open and accessible market for network services, a DSO will enable competitive access to markets and the optimal use of [Distributed Energy Resources,] DER on distribution networks to deliver security, sustainability and affordability in the support of whole system optimisation. A DSO enables customers to be producers, consumers and storers of energy, enabling customer access to networks and markets, customer choice and great customer service."

In practice, the terms "DNO" and "DSO" tend to be used interchangeably to describe the distribution network owners / operators, with increasing responsibilities to actively manage their networks.

3.6.2. Actions of DNOs/ DSOs

DNO / DSOs are expected to investigate procuring flexibility as an alternative to network reinforcement [183], or an activity to manage a network capacity constraint, while a reinforcement is planned but cannot be done straight away.

For example, SP Energy Networks (SPEN), which owns and operates two license areas, SP Manweb (SPM) in north west England and North Wales, and SP Distribution (SPD) in southern Scotland, had its first flexibility tenders in 2019, all in its SPM area, and procured 53 MW of flexibility capacity [184]. All tenders were long term, for at least several months. Volumes are tabulated in Chapter 3 Annex 8,

Table 78.

"Stored energy" assets, presumed to be batteries, were among tender participants in tenders for all delivery years from 2021/22 onwards [185]. Most of their were unsuccessful: most successful providers were fossil gas or demand. However, batteries were contracted to provide 4.7 MW of "Dynamic" service, at Connah's Quay in North Wales, over winter 2021/22, and 0.2 MW of "Secure" service at Kaimes in SPD area over winter 2024/25, whole year 2025/26, winter 26/27, and winter 27/28. A further 0.1 MW of stored energy was contacted to provide the "Secure" service over winter 2027/28 at Fiddlers Ferry in Manweb area. In all cases, service windows were in late afternoons and evenings. Required delivery durations and response times in most cases were 1 hour / 15 minutes, with the Connah's Quay 2021/22 offering requiring 3 hours provision responding within 15 minutes. Availability prices for batteries ranged from £5 /MW/hr to £270/MW/hr. Projected daily revenues, based on availability prices and agreed service windows, ranged from £16.50 / MW/day on weekdays only for winter 2021/2022, up to £625 /MW/day (every day), for winters 2026/27 and 2027/28. Bespoke utilisation prices were also agreed in the tenders, which ranged from £28 - £400 / MWh. Results are tabulated in Chapter 3 Annex 8 Table 79.

Regarding the year 2022-2023, which is studied in greater detail in the following chapters, in these two DNO areas, contracts for just under 30 MW of flexible capacity were awarded, at 2 sites in SPM area, all to fossil gas providers. Around one third of the capacity accepted was for long delivery durations, 10 hours, which commercial batteries are currently unable to offer at full power. Availability prices were modest, at zero to £5 / MW/ hour for short-duration offerings, and up to £40 / MW / hour for longer-duration offerings; utilisation prices of £100 - £1000 / MWh were agreed. These results are tabulated in Chapter 3 Annex 8 Table 80.

Almost 8 MW of batteries in SPD area, and 43 MW in SPM area, offered flexibility services for year 2022-23, in bids which were either unsuccessful or later withdrawn by the provider. These results are tabulated in Chapter 3 Annex 8 Table 81. For the following two years, very limited volumes of flexibility capacity were procured (22 and 56 MW), respectively, in total across both licence areas), but it was procured at many locations, with availability prices for a few small providers exceeding £1000/ MW day, as shown in Chapter 3 Annex 8 Table 82. Reasons for flexibility *not* being contracted, reported by SPEN, include: "bid uneconomic", "interim services no longer required", and "insufficient capacity offered". No tenders were held in 2022, but SPEN expressed an expectation of running tenders from 2023 onwards [184].

In short, during 2022, there was limited opportunity for batteries to accrue significant, or indeed any income from provision of DSO flexibility services. Opportunities were dependent on location and the price at which the DNO / DSO was prepared to accept bids, as well as competition from other types of provider. However, much increased procurement of DSO flexibility services is expected in the coming few years. Much higher prices have been agreed for service delivery during 2024/5-2027/28, albeit at small volumes. Opportunities are therefore likely to increase.

As stated in Chapter 2, the literature reports mixed results regarding projected effectiveness and cost-effectiveness (or otherwise) of using storage as an alternative to reinforcement; however there are some clear cases e.g. [73] where energy storage would be a useful to manage a constraint pending reinforcement. However, the temporary nature of such a use may be a barrier to a storage unit having a viable business case. Relocatable energy storage units – the subject of a little academic interest (as described in Chapter 2) - may be an option in such circumstances, if a practical and economic relocatable solution could be built and made to work.

3.7. What would a battery do? Summary and concluding remarks

Potential incomes a battery could earn from the activities selected here are summarised in Table 14.

Table 14 Potential income of a 1 MW battery – alternative revenue streams

Type of Service or activity	Service / activity	Unit	Notes	Can conduct simultaneously with wholesale trades?	Battery duration	Potential revenues		
						2022/2023	2023/2024	2024/2025
Frequency response	**Most lucrative service (usually DC)**	Average £ per day		No [34]	~ 1 hour duration for fastest services.	> £800 (May / Jun); ~ £200-300 Nov/Dec	Not enumerated.	Not enumerated.
Reserve services	**Not specified**			No	Longer duration	Not enumerated.	Not enumerated.	Not enumerated.
Wholesale trades	**Wholesale trades**			n/a	1 Settlement Period (0.5hr)	Calculated in Chapter 4	Not calculated	Not calculated.
Balancing Mechanism	**Balancing Mechanism**			Yes [35]	1 Settlement Period (0.5hr)	Not enumerated	Not enumerated.	Not enumerated.
Capacity Market	**Capacity Market**	£ / day, over the year (or length of contract)	Prices varied between individual CM auctions	yes	1 hour	£4 - £53/day	£9 to £31/ day	Not enumerated.
					2 hour	£8 - £104 / day	£18-£61/day	Not enumerated.
					4 hour	£12 - £154 / day	£29-£102/day	Not enumerated.

[34] A provider cannot offer frequency response or reserve services using the same MW of capacity which it is using for wholesale trades at the same time. However, a provider could offer part of its capacity for different activities or services simultaneously. It could also change between different services or activities within the same day.

[35] Any BM instructions from the ESO take precedence over wholesale trading activity, and are compensated at the pre-agreed price.

Type of Service or activity	Service / activity	Unit	Notes	Can conduct simultaneously with wholesale trades?	Battery duration	Potential revenues		
						2022/2023	**2023/2024**	**2024/2025**
TNUoS	**Avoidance of demand TNUoS charges**	**£ / day [36],**	Applicable to “behind the meter” batteries	**yes**	**~ 2 hours [37]**	£352 (N Scotland) - £817 (SW England)	£0 (Scotland, N. Eng. & N Wales) - £98 (SW Eng.)	£0 (Scotland, N. Eng. & N Wales) - £105 (SW Eng.)
	Embedded export TNUoS credits		Applicable to DN-connected generators			£0 (Scotland, N. Eng. & N Wales) - £118 (SW Eng.)	£0 (Scotland, N. Eng. & N Wales) - £131 (SW Eng.)	£0 (Scotland, N. Eng. & N Wales) - £140 (SW Eng.)

[36] £/day, averaged over 78 winter weekdays excluding holidays
[37] Likely to be necessary to cover all likely Triad SPs

Type of Service or activity	Service / activity	Unit	Notes	Can conduct simultaneously with wholesale trades?	Battery duration	Potential revenues		
						2022/2023	2023/2024	2024/2025
DUoS, HV-connected sites.	**DUoS "red band" demand charges avoidance**	**£ / day (all year)**	Applicable to "behind the meter" batteries	yes	3 hours	£59 (London); £91 (S. Scotland)	Not enumerated.	£100 (London) £118 (S. Scot)
				yes	*~ 5 or 6 hrs[38], London only*	*£117 (London only)*	*Not enumerated.*	*£199 (London only)*
	DUoS "red band" export credits – HV-connected sites		Applicable to HV-connected generators / exporting sites	yes	3 hours	£89 (London), £108 (S Scotland)	Not enumerated.	£114 (London), £141 (S. Scot)
				yes	*~ 5 or 6 hrs London only*	*£177 (London only)*	*Not enumerated.*	*£227 (London only)*
DUoS – EHV-connected sites	**DUoS "super red band" demand charges avoidance**	£ / day (all year)	All tariffs are site specific. Most are zero or near zero. Applicable to "behind the meter" batteries	yes	3 hours (London only, 5 or 6 hours)	Zero up to £91/day (S Scotland. *(Up to £117/day in London if can export for 6 hrs)*	Not enumerated.	Zero up to £118 / day, S. Scot. *(Up to £199/day in London if can export for 6 hours)*
	DUoS "Super Red Band" export credit tariffs	£ / day (all year)	All tariffs are site specific. Most are zero or near zero. Applicable to EHV-connected generators / exporting sites	yes	3 hours (London only, 5 or 6 hours)	Zero up to £108/day (S Scotland). *(£177/day in London if can export for 6 hrs)*	Not enumerated	Zero up to £141/day (S. Scotland). *(Up to £227/day in London if can export for 6 hrs)*

[38] Able to operate for two 3-hour red band periods in a day, with limited (2-hour) time in between, during which some recharging may be possible

Type of Service or activity	Service / activity	Unit	Notes	Can conduct simultaneously with wholesale trades?	Battery duration	Potential revenues		
						2022/2023	2023/2024	2024/2025
DSO Flexibility services	Bespoke by DNO	Could be utilisation or availability	Services bespoke to the DNO and locality	Probably not	Bespoke to service	Within SPEN areas: Successful bids – 30 MW across 2 locations, all gas providers. £0-£20/day availability, with utilisation fees of £400-1000/MWh.	Within SPEN areas: Successful participants, 22 MW across many locations, all demand or fossil gas, some with storage (battery / hydro) as a secondary technology. Availability payments £0 - £270/MW/day, some exceeding £1000 / MW/ day. Utilisation payments £30-£500/MWh	Within SPEN areas: Successful participants, 52 MW across many locations, mix of demand, fossil gas and storage providers. Availability payments £0 - £270/MW/day, some exceeding £1000 / MW/ day. Utilisation payments £28-£800/MWh. Among providers, an estimated £210 / day availability price, over the winter, awarded to a battery at one location.

Good potential revenues were to be made from frequency response services, over £800/ day in early summer 2022. Potential revenues fell towards the end of 2022, to around £200-300 / day, though higher prices occurred on some occasions.

Some batteries, large enough to be registered as stand-alone participants in the BM [39] [40], were active in conducting wholesale trades, potential revenues from which are investigated in the following chapter. Potentially significant income could be made from BM activity, though it is the ESO which selects providers. BM activity among batteries during 2022 was much less frequent than wholesale trades.

Some batteries were awarded CM contracts, which provide a small but regular additional revenue stream. Such contracts will only occasionally affect batteries' actions outside of the exceptional instances of a CM notice period, and even then, batteries engaging in ancillary services such as frequency response, or balancing actions, will be exempt from further actions. Any CM period would inevitably be accompanied by very high wholesale trading prices, conditions which would strongly encourage exports, whether or not bound to do so by CM contracts.

DUoS credits for distribution-connected batteries (not behind the meter) could reward HV-connected batteries for exports during afternoon / evening peak times by around £100 / day. DUoS rewards for EHV-connected batteries are likely to be lower or zero. If located in southern Britain only, the batteries may also be eligible for Embedded Export Tariffs TNUoS credits, for exports at the same time of day during the winter, potentially accruing up to an additional £100 / MW / day over the winter months, depending on location.

Batteries located "behind the meter", sharing a metering point [41] with a large electrical demand site, could accrue similar revenues from a combination of avoidance of DUoS, and, in southern England and South Wales, avoidance of TNUoS "Triad" demand charges. During 2022/23 and previous years, TNUoS charges avoidance ("Triad avoidance") benefits were far higher, around £300-800 / MW/ day (over 78 days/ year of activity over the winter); "Triad

[39] i.e. Balancing Mechanism Units, BMUs. BMUs conduct trades and submit their own prices for bids and offers. They have their own identifiers and their actions are recorded in BM data.
[40] Smaller assets can also participate indirectly within the BM, for example via aggregators, without registering as BMUs; they would be in contract with a third party (e.g. aggregator). BM data would identify the actions of the third party (e.g. aggregator) only.
[41] More precisely, a Metering Point Administration Number (MPAN), which is a unique identifier for a customer's electricity meter.

charges" fell sharply, to levels similar to Embedded Exports Tariffs from 2023/24. Besides DUoS / TNUoS credits, batteries could engage in other activities, especially at weekends or any other days when DUoS / TNUoS credits or charges avoidance do not apply or are unlikely. Behind the meter location of batteries may complicate engagement in some other activities.

Opportunities for revenues from DSO flexibility services were extremely limited in 2022, and prices were modest. However, demands and prices for these services have risen the last few years.

In short, there are several potential revenue streams which are realistic for GB batteries, and many engage in multiple activities [112].

The constraints of the PhD do not allow in-depth exploration of all options. The rest of this PhD thesis concentrates on one of the activities, wholesale trades, as it is expected that significant volumes of battery capacity will continue to engage in this activity. This expectation is based on several reasons:

- Wholesale trading was among the activities that numerous real grid-connected batteries engaged in during 2022.
- 2022 was the first year during which the battery storage industry reported wholesale trades became financially competitive with frequency response, citing connection of greater numbers of batteries causing "saturated markets" and lower clearing prices for ancillary services.
- Increasing numbers of battery connections would appear to make this situation seen as likely to continue beyond 2022.
- Given the enormous quantity of connection requests from batteries, whenever aggregate available battery capacity will exceed that required for grid services, wholesale trades is a revenue-accruing activity which the remaining batteries would be allowed to engage in.

Furthermore,

- Wholesale trades may be conducted with the same battery capacity used
    - for network use of system credits, whenever patterns of wholesale prices coincide with those of network charges.
    - For Capacity Market availability payments, unless a (likely to be rare) Capacity Market event requires their deployment

The following chapter (Chapter 4) investigates potential revenues a battery may accrue from engagement in wholesale trades, and what patterns of activity would be likely. Later chapters explore potential effects batteries' engagement in wholesale trades could have on network congestion at Transmission level (Chapter 5) and Distribution level (in Chapter 6).

4. Chapter 4. Battery wholesale trades: simulation methodology and results

Chapter summary

This chapter describes an agent-based model that was created to simulate the actions of an economically rational battery, engaged in wholesale trades, to explore the battery's possible interactions with other network users and any impacts on network congestion. This work assumes that the battery is privately owned and its owner is intent on maximising overall net income from energy trades. Battery activity was simulated for three 5-week case study periods in 2022 ("summer", "autumn" and "winter"), using real wholesale price data from the Nordpool Day Ahead platform. Results suggest that a 1MW / 2 MWh, with 85% round-trip efficiency, intended to represent a lithium ion or similar battery, could accrue average overall daily net revenues from energy trades of between £157 (in "summer") to £354 (in "winter").

The above simulated battery tended to engage in two daily trades most days during the "summer" and "autumn" case studies, and one daily trade most days of the "winter" case study. The times of day of trades were fairly consistent, with early evening exports and night time imports, and in summer and autumn, an additional morning export and midday import on many days. This diurnal pattern of behaviour was also found for batteries of durations 1-4 hours, and of 12 hours duration (70% round trip efficiency), intended to represent a flow battery. However, the longer duration battery had very different timeseries of activity to batteries of shorter duration, with many days of inactivity. Batteries of 1 and 2 hours duration had the highest overall net incomes per MWh of battery capacity.

Simulated battery activity was compared to that of 23 real BMU batteries active during 2022, described in the previous chapter. Though there were differences in behaviour between batteries, diurnal patterns of behaviour between simulated and real batteries were broadly similar. In every case study season, there were examples of real batteries displaying similarly-timed imports and exports as those of a simulated 2-hour battery. It was concluded that the battery simulations are close enough to the actions of enough real batteries to validate this model. The chapter ends with a discussion of the strengths and limitations of the battery model, and concludes that the model's outputs can be used to inform interested stakeholders of examples of likely behaviour of rational batteries engaged in wholesale trades.

Finally, potential incomes from wholesale trades were compared to other activities a battery could engage in, enumerated in Chapter 5. Potential overall net incomes from wholesale trades compare fairly favourably with those of other activities during the autumn and winter case studies of 2022, and could be accrued in addition to incomes from Capacity Market, for successful participants, and potentially also Use of System network credits. During the summer case study period, higher incomes could be gained from frequency response services, though wholesale trades would be a realistic revenue stream for any batteries unable to provide such services. It was concluded that wholesale trading, as a sole activity, or in combination with other activities, was a viable option during 2022, particularly during the "autumn" and "winter" case study periods, and also one which a number of real batteries had engaged in.

Outputs from this chapter are used in analysis in later chapters into the likely effect of battery trading activity on electricity network congestion at both Transmission and Distribution level, using case studies of and within Scotland.

4.1. Chapter introduction and aims

The aim of this work is to simulate actions that a "rational battery" would do, in a GB context, if engaged in wholesale trades. In particular, it seeks to understand likely power flows from battery at any given point in time, in order that such flows can be considered together with actions of other electrical networks users, and potential effects on network congestion surmised.

A model to this end is constructed.

In this work, a "rational battery" in a GB context is defined as being independently owned, and having an owner or controller which is taking economically rational decisions, with the intent of maximising overall revenue [42]. It is assumed that the battery owner / controller has timely access to at least some information about forthcoming wholesale spot prices (a matter elaborated later in this chapter), and the facility to use such information in directing battery energy flows.

This chapter also seeks to investigate the financially viability of wholesale trades, compared to other activities a battery might undertake, as described in the previous chapter, to surmise if

[42] The relevance of battery ownership to its patterns of activity has been discussed in Section 2.3 and 2.4. Chapter 3 is entirely in the context of independently owned battery in GB.

this is a realistic option for batteries. This chapter seeks to refer to actions of real batteries, as described in Chapter 3, for validation.

4.2. Review of approaches to battery simulation

There is a large body of literature describing approaches to the modelling of batteries and other types of energy storage, and their behaviour in electrical power systems.

Regarding model formulation, many studies on behaviour of storage and other flexible energy resources on electrical power system use optimisation algorithms [186], with objectives such as maximising income for a storage asset engaged in arbitrage [187], or integration of renewable energy and storage assets in a residential setting [188], microgrid [189], or regional power system [190], at lowest operational or system cost.

A different approach to modelling the behaviour of energy storage assets is agent-based modelling. The application of agent-based simulation of actions of various users or assets which connect to or form part of an electrical power system (e.g. generators, consumers, storage assets), is established in both a microgrid setting, and also in a deregulated power market [191]. An early example of the latter was an investigation into potential outcomes of the New Energy Trading Arrangements in England and Wales, at around the time of their introduction, in 2000 [192]. More recent examples of agent-based modelling investigate flows of electrical power and money within local communities in which there are local renewable energy assets, consumers, prosumers and energy storage [193]–[195].

In [196], Ma and Nakamori investigated different approaches to simulation of long-term changes in generation mix of a simplified electrical power system. They compared the use of optimisation algorithms, with and without "endogenous technological change" functionality, with each other and with a simple agent-based model, and concluded that all approaches had advantages and limitations. The authors remark that *"optimization models can tell us 'what should be' in terms of reaching some objective... while satisfying... constraints*", whereas "*agent-based models can tell use 'what could be' under various assumptions*". The authors suggest that the more suitable modelling approach for a piece of work would depend on the purpose of the decision-making, and that these modelling approaches should be viewed as complementary in furthering understanding of energy systems. Numerous works, such as [197], [198], indeed combine agent-based methods with optimisation in investigating behaviour of energy storage on electrical power systems.

Aside from model formulation, there is a question of the appropriate level of detail with which to model the behaviour of the storage asset. From a power systems perspective, an idealised approach to modelling a storage asset on an electrical network, would describe the asset as a technologically-neutral “black box”, which can deliver energy and recharge according to fixed parameters, with a nominal efficiency, and potentially standing losses. Vykhodtsev et al in their review of approaches to modelling of lithium ion battery storage [186], describe the “black box” (power-energy) model as the most widely used approach, such as in [199], but describe limitations of this approach. These authors, and Mao et al [200] describe three general paradigms for modelling of lithium batteries, and storage more generally, respectively, in analyses of power systems, which are summarised in Table 15.

Vykhodtsev et al [186] describe a generic “power-energy model “ as being described by Eqn. (4.1), within the limits of the battery's energy capacity, and with the following parameters:

State of Energy, i.e. energy contained in the battery at time t (MWh)	*SoE (t)*
Power drawn while charging, at time t (MW)	*P_charging (t)*
Power delivered when discharging, at time t (MW)	*P_discharging (t)*
Efficiency of charging (fraction)	*η charging*
Efficiency of discharging (fraction)	*η discharging*
Timestep (hours)	*timestep*

$$SoE\ (t) = SoE\ (t-1) + timestep.\left(P\_charging(t).\,\eta charging - \frac{P\_discharging(t)}{\eta discharging}\right) \qquad (4.1)$$

[186] give examples of ways in which some researchers have embellished the generic power-energy model, by adding dependencies of power flows and/ or round-trip losses on SOC, or of round-trip losses on power flows. Mao et al [200] also describe improvements to the “black box” approach, from both “empirical” and “data-driven” modelling. Both studies describe the “grey box” / “voltage-current” model, and “white box” / “concentration-current” approaches as giving progressively more accurate simulations of battery behaviour, but with increasing trade-offs of greater computational complexity.

Table 15 Summary of approaches to modelling batteries / energy storage assets in power systems [186], [200]

Model paradigm	**"white box"**	**"grey box"**	**"black box" (simple case)**
Other names	"physics-based model", "concentration-current model" (batteries only)	"equivalent circuit model", "voltage-current model"	"power-energy model"
Aim	A model which most closely approximates to actual behaviour	A compromise between accuracy and complexity. Represent battery (or other storage asset) behaviour with electrical circuit parameters	A simple and widely applicable model
Principle	Include thermodynamics and kinetics of specific processes within the battery cell (or other type of storage asset)	Describe the battery (storage asset) in terms of an equivalent electrical circuit, in which V and I, with R and in some cases C components, represent phenomena within a battery cell (the storage equipment)	Described by Eqn (4.1), within capacity limits of the battery
Parameters	have dependencies	have dependencies	usually fixed
Computational complexity	high	low-high	low[43]
Accuracy	high	medium- high	medium [44]
generalisability	low	medium	high
timescales	ns-ms	ms, min-hr	min-hr[45]

With batteries and potentially other assets being required to or rewarded for potentially performing multiple activities simultaneously, such as frequency response and arbitrage, Vykhodtsev et al [186] raise particular concerns of the ability of the "black box" model to give appropriate results over very short and over multiple timescales. Mao et al [200] propose an approach to simulating activity on multiple timescales, and suggest a flowchart to aid selection of suitable model elements, Figure 15.

Energy arbitrage was the most widely-researched application of battery models reviewed in [186], Vykhodtsev et al's study; almost all of those studies used a "power-energy" model, in

[43] Mao et al – low; may be medium in the case of black box with data-driven improvements
[44] Mao et al – may be "high" with data-driven modelling improvements
[45] Mao et al - may be ms-s with empirically-driven improvements

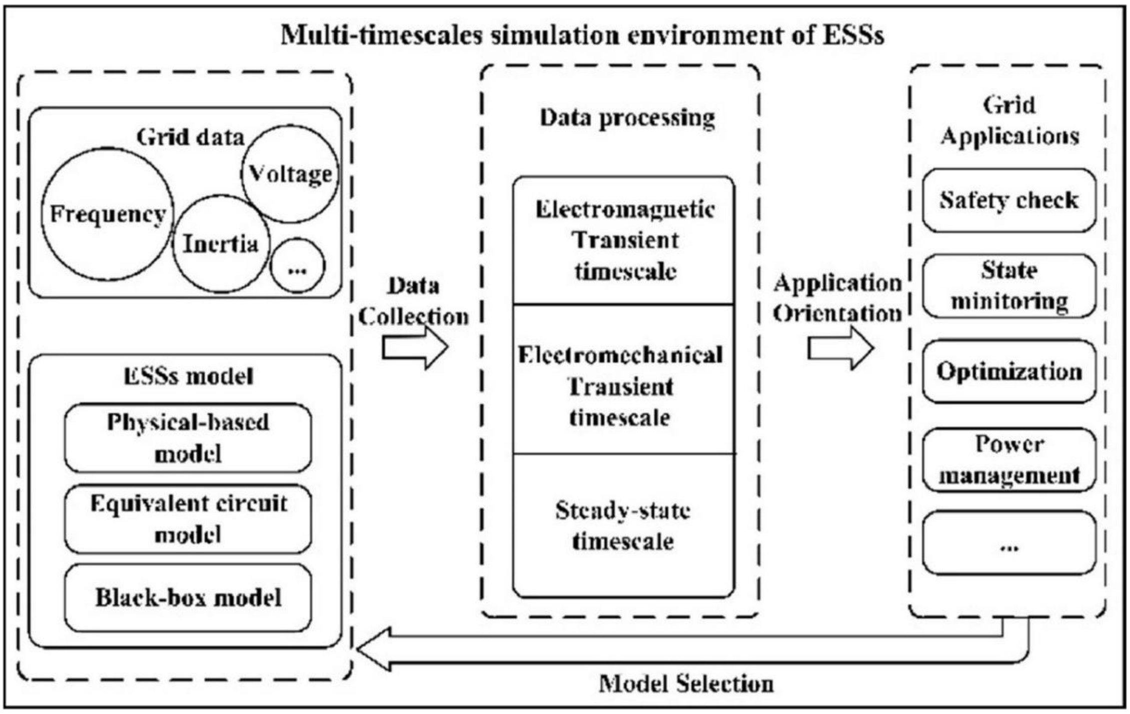


Figure 15 Multi-timescale simulation environment of energy storage systems. Reproduced from Mao et al [200]

some cases with additional improvements, and around half attempted to take degradation into account in some way.

Battery degradation must be mentioned here. [201] describes some of the complexities inherent in attempting to model this phenomenon: degradation appears to occur through multiple mechanisms, and depends not simply on number of cycles, energy throughput or calendar age, but crucially on environmental factors (primarily temperature) and operational factors (especially the degree / depth of charging and discharging). Some physics-based models attempt to simulate degradation reactions; some studies have incorporated battery degradation more simply into a “black box” model, by enforcing operational limits, or by counting total energy throughput or battery cycling [186], or by use of “empirical modelling methods” [200]. Sobon’s thesis [202], and her and Stephen’s paper [203], describe current approaches to simulation of battery health and degradation, and propose a decision support tool to predict battery mal-operation. This tool could potentially be used together with a battery schedule optimiser, to incorporate battery health considerations into scheduling decisions. [204] reports that the use of physics-based modelling constraints for batteries engaged in wholesale trades succeeded in reduced degradation and improved whole-life performance of batteries. This is clearly an important area of ongoing research.

4.3. Battery Model - overview

4.3.1. Aim

As stated in this Chapter's introduction, the aim of this work is to simulate actions that an "economically rational battery" based in GB could be expected to do, if engaged in wholesale trades. In particular, this chapter seeks to produce timeseries of likely power flows from a battery, in order to understand any interactions with electricity generation or consumption by other users of electrical networks, and any impacts on network congestion.

In order to understand likely behaviour of a battery engaged in wholesale trades, an understanding of likely revenues is necessary, in order to choose financially plausible scenarios of battery actions. Battery cycling behaviour is also an aspect which could potentially affect scenario selection, and so is also considered in this chapter.

4.3.2. Choice of modelling approach

Clearly, a number of modelling approaches could have been used in this work.

Regarding model formulation, various approaches, including an optimisation or an agent-based approach (or some combination of the two) could be appropriate. The key objective of this modelling is the output of a credible timeseries of power delivery and consumption of a battery, in order to inform a network operator or system planner of potential behaviours of batteries on networks. Ideally this study would include multiple scenarios. While battery owners themselves are likely to wish to optimise their incoming cashflows, an "optimal" action may depend on external factors, such as the business model chosen, the interaction between battery cycling, useful lifetime and possibly warranty conditions, and a battery owner's possible wish to engage in multiple activities, all factors beyond this study. An agent-based approach, to describe "*what [battery actions] could be*" [196] is thus considered more useful and has been selected. Scenarios are selected which are intended to depict credible actions of a battery owner.

Regarding the degree of complexity appropriate for this model, for arbitrage activities, likely to be around 1-2 cycles a day, this pattern of activity is within the timescale where a simple "black box" model is considered to give an acceptably reasonable estimate of behaviour, and the complexities of the "white box" and "grey box" ("physics-based" and "equivalent circuit based") are not justified for an initial study. They may be considered for future work. Incorporating battery degradation, not performed in this study, would also add to complexity of the model. It would be ideal to incorporate some reference to degradation, insofar as it might affect modes of operation of the battery; these are considered as sensitivities in some of the modelling runs.

4.3.3. General principles and overall formulation

A battery owner, wishing to engage in wholesale trades, would wish to import energy at times of low price, and sell at times when the price is higher, as described in [187].

This model simulates such decisions, for three case study periods during 2022. The model is a single-agent model that represents rational decision making of a battery operator, as shown schematically in Figure 16.

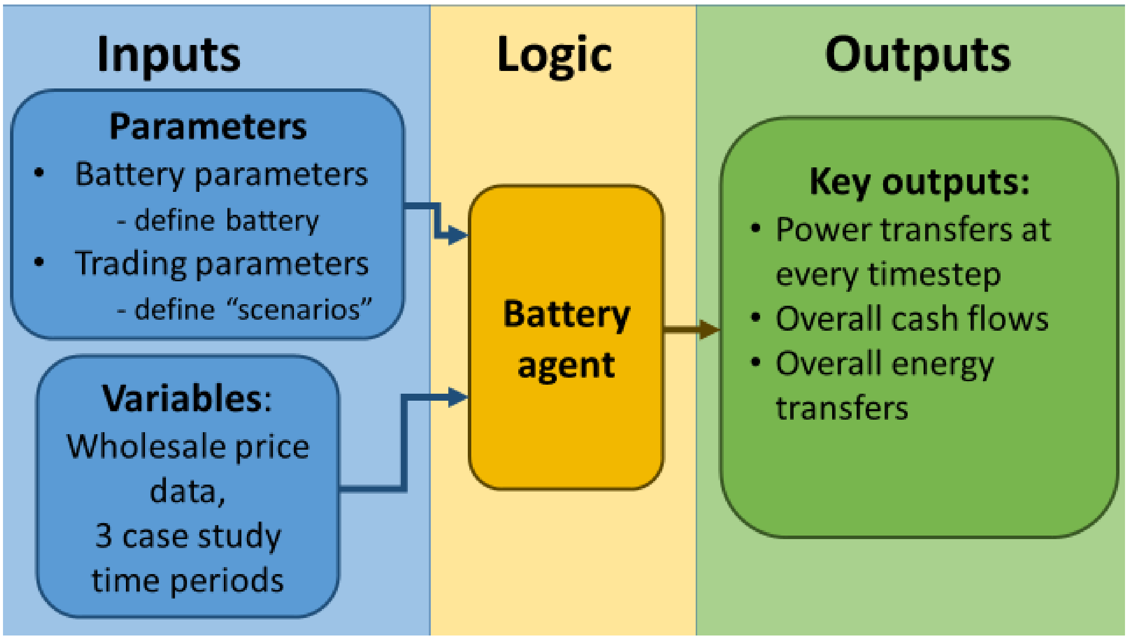


Figure 16 Schematic of battery model formulation

4.4. Model inputs

4.4.1. Variables: electricity wholesale price datasets

4.4.1.1. Nature of the variables

The input variables are contained in a timeseries dataset of GB wholesale electricity prices. The key variables are:

Dataset temporal resolution (hr)	timestep

And at any time t:

Wholesale price (£/MWh) at every timestep	price(t)

4.4.1.2. Price datasets

There is no *single* price for electricity within GB, as trades can occur bilaterally between generators, suppliers and other entities. Spot markets are available for day ahead and in-day trades, run by two companies: Nordpool and EPEX [205], [206]. Price datasets can be purchased from these companies at commercial rates. Nordpool and EPEX prices can be viewed without cost online (though not downloaded); visibility of EPEX prices on its website is restricted to within a few days of the viewing date. Intraday spot prices are available for free download from Elexon's Market Index Price data [207]. Day ahead prices can be downloaded without cost from ENTSOE website [208], [209]; unfortunately, available data for GB do not go beyond the end of 2020.

For a battery owner, there are pros and cons of trading in day-ahead auctions, intraday auctions, and the continuous intraday market. Overall volumes of trades are highest in the Nordpool day-ahead auction [210]. Day-ahead prices give greater certainty and enable planning and easier optimisation of an asset's schedule, which may explain why GB battery systems appeared to favour these platforms, as of 2023 [211]. (This feature of day-ahead platforms may explain why retailer Octopus uses them rather than intraday prices for its "agile tariff" offering [212].) However, intraday prices tend to be more volatile than day-ahead, thus providing greater opportunity for the most profitable battery trades [211], but also presenting the risk of a "worse" price profile for a battery (compared to that of a day-ahead platform), and also of prices differing from forecasts, which could prevent best use of assets. Price deviations from forecasts and other platforms are most likely in the case of EPEX's continuous intraday platform [210].

The model can run on both intraday and day ahead price data. The scenarios selected for this work use day-ahead prices, which is typical of actual batteries. However some battery systems do use intraday platforms, and thus would be guided by prices which at times will differ from the prices used in this work.

All simulations used Nordpool Day Ahead price data, which are of 1-hour resolution. The data were all manually transcribed, and so may contain transcription errors.

4.4.1.3. The three case study periods

As stated in the previous chapter, this study uses three 35-day case study periods during 2022, selected to include different conditions of weather, demands and wholesale prices, as summarised in Table 16 (presented earlier in the previous chapter as Table 6). Inspection of different conditions of these factors is used in the following chapters to investigate possible interactions between expected battery behaviour, wind generation, and electricity demands.

Table 16 Case study seasons

Season	Start date	End date	Scottish BM Wind availability (combined onshore and offshore)	Wholesale electricity prices	Weather
"Summer"	26 May 2022	29 Jun 2022	Low for most of the period, with several short-duration high-wind episodes	Relatively low and with low volatility for most of the time, with a few episodes of small price spikes or dips.	Mostly sunny and warm
"Autumn"	25 Sept	29 Oct 2022	High for most of the period, with brief lower-wind interludes.	Significant volatility during early part, with prices becoming lower and calmer towards the end.	Mild and windy
"Winter"	17 Nov 2022	21 Dec 2022	Moderate to fairly high at the very start and end of the case study. A prolonged (cold) low-wind period in the middle, with near-zero wind for a few days.	Initially moderate. Very high price spikes during the early evening peak on a few days during late Nov and early Dec. The early December cold snap saw high prices with a large diurnal price range. Prices fell sharply near the end of the case study period, coinciding with a change in weather.	Mild and windy, then very cold and calm, ending on milder windier weather

Wind availability and outputs were ascertained from Balancing Mechanism data.

Inspection of price data for the Irish electricity market, available for free download from ENTSOE [208], [209], was used as a guide to likely prices within GB, the Irish system being heavily interconnected with the GB one.

The wholesale prices timeseries charts are displayed in Figure 17.

Clock times are as downloaded from the Nordpool and are in CET / CEST, one hour earlier than UK clock time.

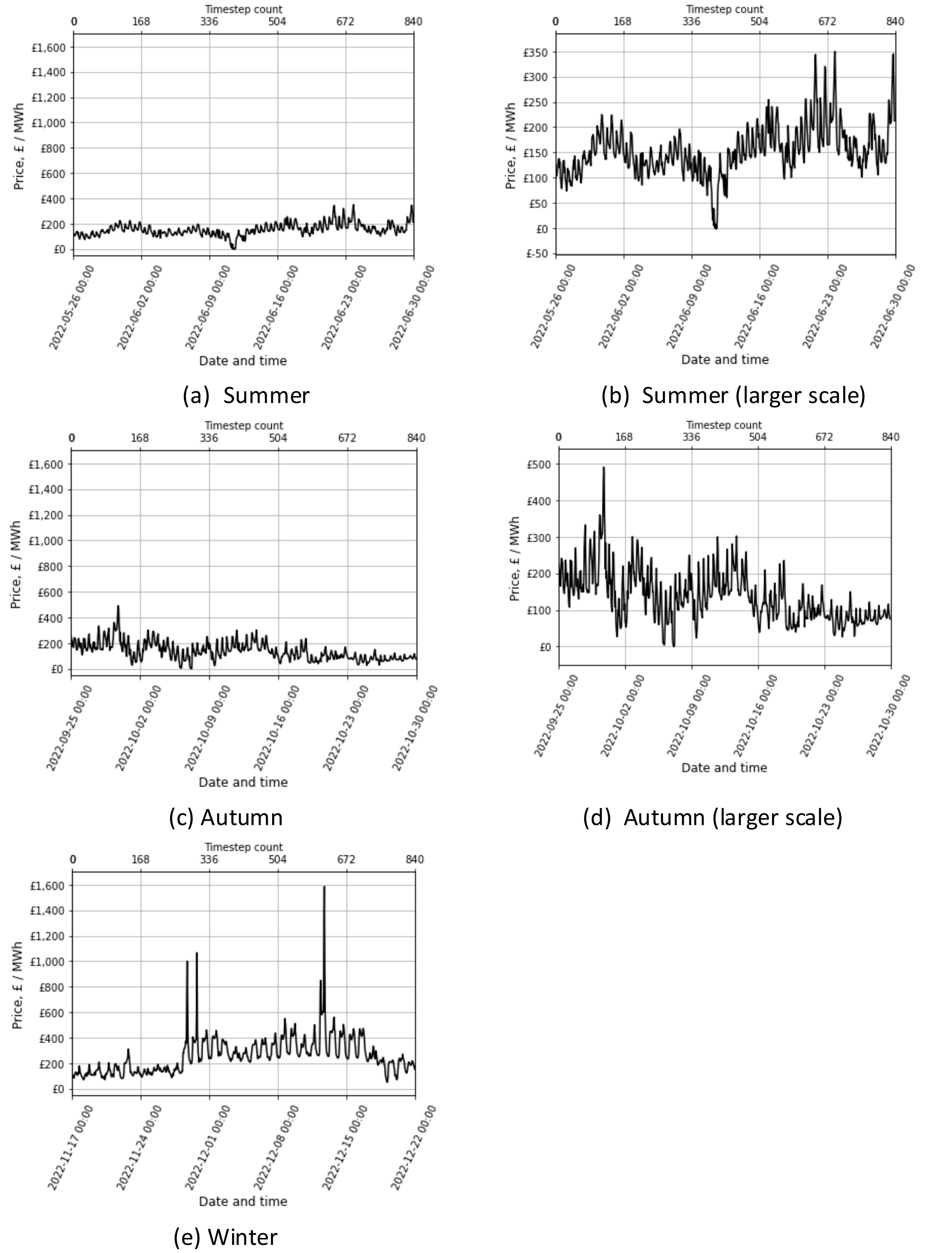


Figure 17 Wholesale prices (Nordpool DA). (a) and (b) - Summer case study; (c) and (d) – Autumn case study; (e) Winter case study

These charts show several features of interest. First, the magnitude and volatility of the prices varied between seasons, and within each season. The summer season had relatively calm and low prices, by the standards of 2022, with in-day variation of around £50-100/MWh, exceeded on only a few days; prices ranged over the whole “season” from £0-350/MWh. The autumn season started with more volatile prices, with in-day price variations up to around £200/MWh, the in-day range reducing to around £50/MWh for the last few days, and a whole-season price range of £0-500/MWh. Both summer and autumn seasons have a high frequency of price variations, which is shown in greater detail in later sections. The winter case study started with relatively calm prices, followed by very high price spikes, of around £1000/MWh, on two days at the end of November, and an even higher price spike in mid-December. The central 2 weeks of the season had a very pronounced diurnal pattern with prices varying daily from £200/MWh to around £400-500/MWh. The frequency of price variations is markedly less than the other two seasons. The magnitude of the prices, the in-day price variations, and the frequency of price variations, all affect the timings and frequency of battery energy flows that a "rational battery" would engage in, as is described in greater detail in the following sections.

4.4.2. Battery Parameters used in the model

4.4.2.1. *Fixed battery parameters*

The fixed battery parameters set the key features of the simulated battery. These parameters are fixed for the whole of every simulation run. For simplicity, the round-trip losses are modelled as occurring only during charging, and not during discharging.

Maximum export power (MW)	*Pmax*
Maximum import power (MW)	*–Pmax*
Simulation timestep (hr)	*timestep*
Battery duration (exporting at Pmax) (hr)	*D*
Battery energy capacity (MWh)	*batt_energy_capacity*
Maximum State of Charge	*SOC_max*
Minimum State of Charge	*SOC_min*
Round-trip efficiency (fraction)	η *(or "eff" in following flowchart)*
Round-trip losses (fraction)	*losses*
Battery duration (importing) (hr)	D_{import}

Where:

$$batt\_energy\_capacity = D.Pmax \quad (4.2)$$

$$losses = 1 - \eta \quad (4.3)$$

$$D_{import} = \frac{D}{\eta} \quad (4.4)$$

Battery energy capacity refers to the *useable* energy capacity, which the battery can discharge repeatedly, from SOC_max to SOC_min, without sustaining damage.

4.4.2.2. Values of fixed battery parameters selected

The battery model initially chose parameters broadly typical of lithium ion batteries, which are commercially viable at present. Some analyses were performed using parameters representative of flow batteries, to illustrate effect of different duration batteries. The values selected are summarised in Table 17.

Table 17 Values of battery parameters used in the modelling

<table>
<tr><th>Parameter</th><th>Default value used in modelling</th><th>Other values used</th><th colspan="2">Comments</th></tr>
<tr><td>timestep</td><td>1 hour</td><td></td><td colspan="2">Value set by resolution of wholesale price dataset</td></tr>
<tr><td>Pmax</td><td>1 MW</td><td></td><td colspan="2"></td></tr>
<tr><td rowspan="3">D</td><td>2 hr</td><td></td><td colspan="2" rowspan="2">2hr, and 1hr and 4hr, chosen to represent Li-ion battery or a similar short-duration battery.</td></tr>
<tr><td></td><td>1hr, 4hr</td></tr>
<tr><td></td><td>12 hr</td><td colspan="2">Limited investigation of 12 hour battery, representing flow battery</td></tr>
<tr><td></td><td></td><td></td><td colspan="2"></td></tr>
<tr><td>SOC_max</td><td>1</td><td></td><td>Defined as maximum safe level of charge</td><td rowspan="2">A battery charge controller is assumed to maintain the SOC within these limits</td></tr>
<tr><td>SOC_min</td><td>0</td><td></td><td>Defined as minimum safe level of charge</td></tr>
<tr><td rowspan="2">η,
and
corresponding
(losses)</td><td>0.85, (0.15)</td><td></td><td colspan="2">Representing total system losses form a lithium ion battery or similar, encompassing losses from ancillary equipment, including inverter, charge controller, battery management system and potentially cooling or heating, as well as the battery itself.</td></tr>
<tr><td></td><td>0.7, (0.3)</td><td colspan="2">Limited investigations
Mainly used with 12-hour duration batteries simulations, representing higher losses from flow batteries</td></tr>
</table>

Standing losses are considered small in comparison to round-trip losses [186], and are not simulated. Similarly, battery degradation is considered to be negligible over the short time period studied, and is not simulated either.

This model considers cashflows only from buying and selling electricity. Other essential business cashflows, such as costs of Operation and Maintenance (O&M) and financing, are excluded.

4.4.2.3. Initial battery parameters

There are further parameters which vary during the course of every simulation.

Initial values are required for the following:

Initial Accumulated cashflow	*Accum_cash* (t=0)	set to 0
Initial State of Charge	SOC(t=0)	set to 0.5 [46]

4.4.3. Trading parameters

The trading parameters represent foresight of market price information, and appetite for trading.

Period of perfect foresight of market price (hr)	*visibility window*
Appetite for trading	*trading strategy*

At every timestep, the battery agent has visibility of the forthcoming prices *within the visibility window,* for example, over the next 2 hours. Trading prices which are favourable for selling energy (high prices) and buying energy (low prices) are determined in comparison to the "*maximum market price*" and "*minimum market price*" within the visibility window, shown in Figure 18.

[46] Unless otherwise stated

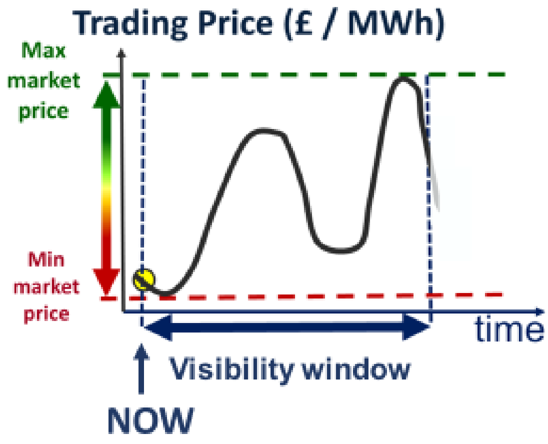


Figure 18 Battery trading behaviour: key parameters [47]Within the range of prices that are about to occur within the visibility window (i.e. time horizon), a "*buy price*" at or below which it is favourable to buy electricity, and a "*sell price*" at or above which it is favourable to sell energy, are set, with the aid of two further parameters: the *market price gap*, and the chosen *trading strategy*.

$$Market\ price\ gap = maximum\ market\ price - minimum\ market\ price \tag{4.5}$$

Market price gap is specific to that timestep, within the forthcoming visibility window of price. The trading strategy sets the point within the market price gap at which prices are deemed favourable for trading. Four different trading strategies were used, which are shown in Table 18.

Table 18 Battery trading strategies

Trading strategy	**Market price at which battery will buy or sell: position within the *market price gap***	
	'x': for *sell price*	**'y' for *buy price***
' 40%' ('Busy')	60%	40%
'25%' ('Moderate')	75%	25%
'10%' ('Wait for good price')	90%	10%
'5%' ('Wait for best price')	95%	5%

[47] In the context of a day-ahead trading platform, "NOW" in Figure 18 refers to the time at which the battery has been committed to operate, or not operate, in an auction the preceding day. In an continuous intraday platform, on the other hand, "NOW" would mean the present time.

$$sell\ price = minimum\ market\ price + x.market\ price\ gap \tag{4.6}$$

$$buy\ price = minimum\ market\ price + y.market\ price\ gap \tag{4.7}$$

These parameters are illustrated in Figure 19.

Figure 19 Battery trading behaviour: market price gap, buy price and sell price

For example, if the minimum market price in the visibility window is £200/MWh, and the maximum is £300/MWh, the *market price gap* is £100/MWh. In the *"40% / busy"* strategy, the battery will buy if the market price falls to £240/MWh or below, and will sell if the market price rises to £260/MWh or above. In the *"5% / wait for best price"* strategy, the battery will only buy if market price falls to £205/MWh or lower, and will only sell at market prices of at least £295/MWh.

The chosen *"trading strategy"* and *"visibility window"*, together form the *"trading scenario"* used for the simulation run, as shown in Figure 20. Visibility windows from 2 hours to 72 hours were used in simulations. [48]

For each simulation run, the visibility window and trading strategy are fixed for the whole run. Simulations were repeated with all combinations of chosen visibility windows and trading strategies.

[48] The effect of increasing length of visibility window is shown in the Results section 4.7.

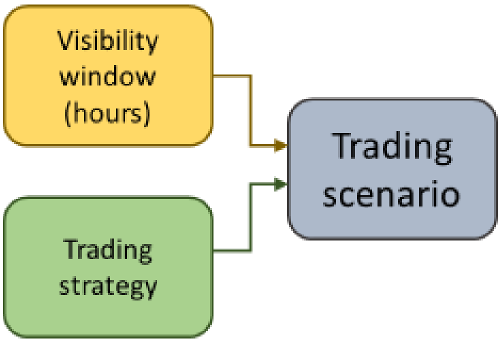


Figure 20 Schematic of Trading Scenario

4.5. Model logic

The battery agent uses deterministic logic to represent the actions of a battery owner, at every timestep.

4.5.1. Introducing the parameters

At every timestep t, the following parameters are calculated and recorded:

power flow (exporting) (MW)	$P\ (t)$
energy exported this timestep (MWh)	$e\_out\ (t)$
energy imported this timestep (MWh)	$e\_in\ (t)$
cashflow increment this timestep (£)	$cash\ (t)$
energy stored within battery after timestep t (MWh)	$stored\_E\ (t)$
State of Charge after timestep t	$SOC\ (t)$

Where
$$stored\_E\ (t) = stored\_E\ (t\text{-}1) - e\_out\ (t) + e\_in\ (t)\ .\ \eta \tag{4.8}$$

and
$$SOC\ (t) = \frac{stored\_E\ (t)}{batt\_energy\_capacity} = \frac{stored\_E\ (t)}{D.\ Pmax} \tag{4.9}$$

When exporting

For $P\,(t) > 0$:

$$e\_out\,(t) = P\,(t)\,.\,timestep \tag{4.10}$$

$$e\_in\,(t) = 0 \tag{4.11}$$

$$cash\,(t) = e\_out\,(t)\,.\,price\,(t) = P\,(t)\,.\,timestep\,.\,price\,(t) \tag{4.12}$$

When importing

For $P\,(t) < 0$:

$$e\_out\,(t) = 0 \tag{4.13}$$

$$e\_in\,(t) = -P\,(t)\,.\,timestep \tag{4.14}$$

$$cash\,(t) = -e\_in\,(t)\,.\,price\,(t) = P\,(t)\,.\,timestep\,.\,price\,(t) \tag{4.15}$$

4.5.2. Determination of power flows, P (t)

At every timestep, the rules encoded in the battery agent, together with the input variables of price and trading scenario, and the battery SOC prior to this timestep, determine whether the battery will import, export, or not trade, and if exporting or importing, at what power.

For a trade to proceed, 3 criteria must be satisfied, as described below. A fourth rule determines the magnitude of power flow of a trade. These rules are summarised in Figure 21.

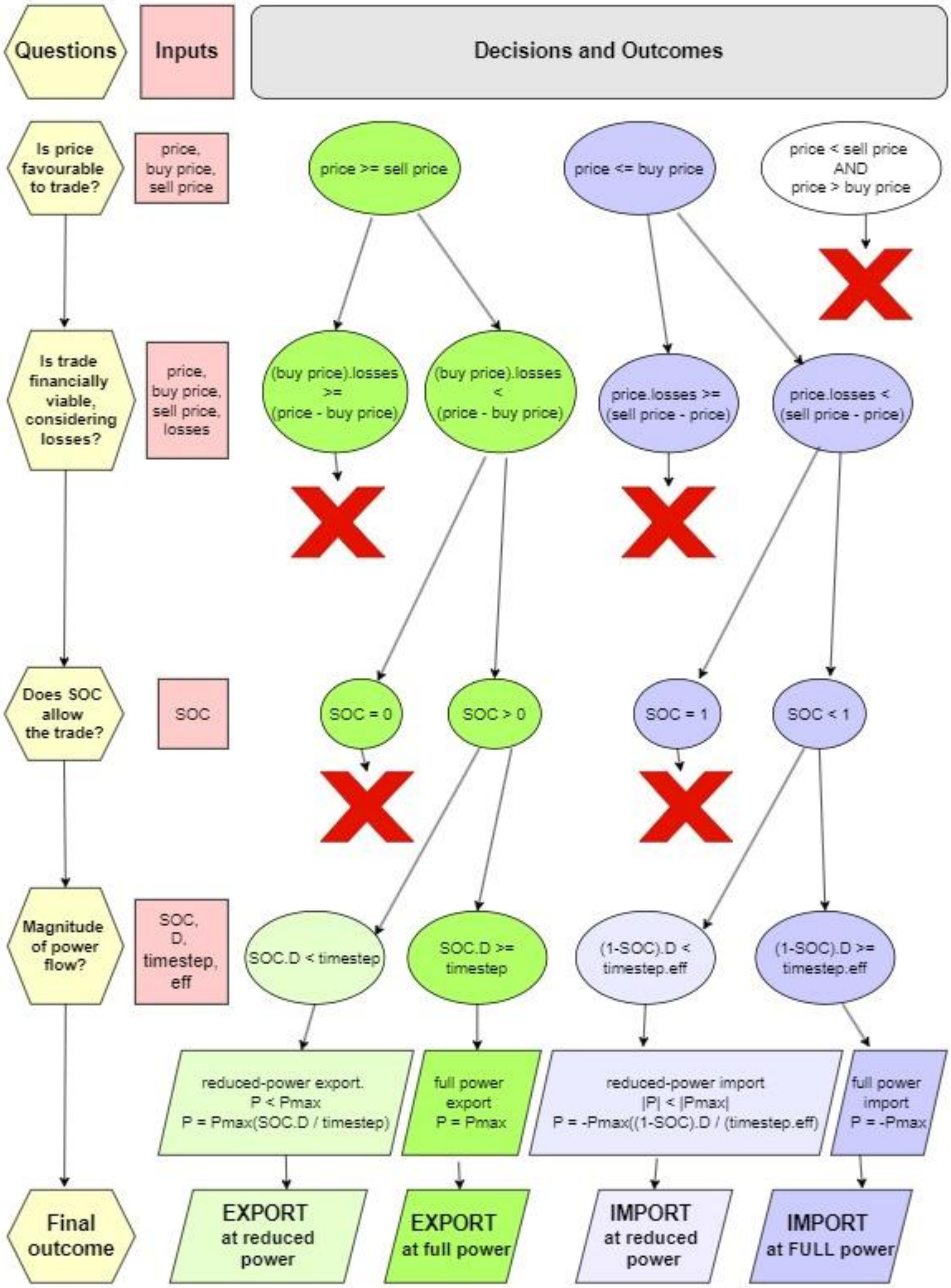


Figure 21 Battery agent heuristics for determining action at each time step.

(Red "X" indicates the trade does not proceed. "eff" is round-trip efficiency, η.)

4.5.2.1. Wholesale Price must be suitable for a trade

As described in Section 4.4.3,

If	$price\ (t) >= sell\ price$	price at this timestep is suitable for export	(4.16)
If	$price\ (t) <= buy\ price$	price at this timestep is suitable for import	(4.17)

4.5.2.2. The envisaged trade must be financially viable, considering the cost of round-trip losses

Trades in which there is only a small difference in price at which energy is bought and sold may be financially loss-making, even if the prices are deemed favourable for trade by the above rule. This situation is especially likely for pricing patterns with small variations in price, for battery scenarios with high round-trip losses (30% or higher), or where trading prices of energy are high. This rule is intended to prevent trades which are financially loss-making or only marginally profitable.

If $\text{projected cost of round-trip losses of this trade}$
$$>= \text{projected net income from this trade} \tag{4.18}$$
then the trade does not proceed.

P (t) = 0

The battery agent has no foresight of the next timestep at which it will next trade; it operates only in the current timestep, with limited foresight of future market prices. So the battery agent uses this timestep's $buy\ price$ or $sell\ price$ as proxies for the price at which it will *next* purchase or sell energy.

Price favourable for export

$$Estimated\ cost\ of\ losses\ from\ this\ trade\ (£/MWh) = buy\ price\ .\ losses \tag{4.19}$$

$$Estimated\ net\ income\ from\ this\ trade\ (£/MWh) = price - buy\ price \tag{4.20}$$

If	$Price - buy\ price > buy\ price\ .\ losses$	(4.21)
which can be expressed as:	$Price - buy\ price > buy\ price\ .\ (1 - \eta)$	(4.22)
then	the export trade may proceed.	
otherwise	the battery does not trade at this timestep.	

This rule, under "exporting" conditions, is illustrated schematically in Figure 22.

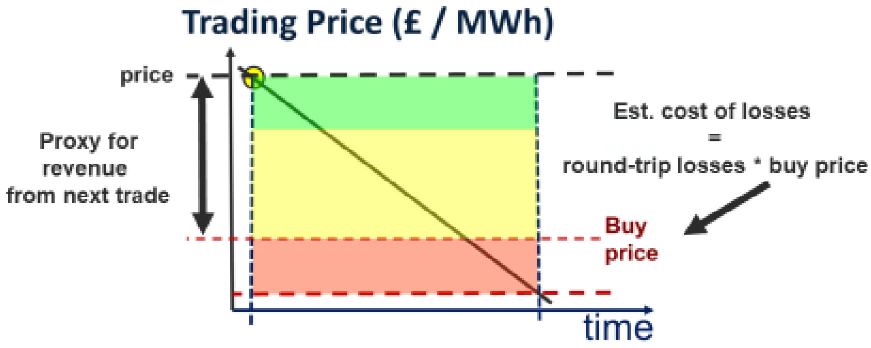


Figure 22 Illustration of "financially viable trade" rule, when price favourable for exporting

Price favourable for import

$$\textit{Estimated cost of losses from this trade (£/MWh)} = \textit{price . losses} \tag{4.23}$$

$$\textit{Estimated net income from this trade (£/MWh)} = \textit{sell price} - \textit{price} \tag{4.24}$$

If	$\textit{sell price} - \textit{price} > \textit{price . losses}$	(4.25)
which can be expressed as:	$\textit{sell price} - \textit{price} > \textit{price . } (1 - \eta)$	(4.26)
then	the import trade may proceed.	
otherwise	the battery does not trade at this timestep.	

This rule, under "exporting" conditions, is illustrated schematically in Figure 23.

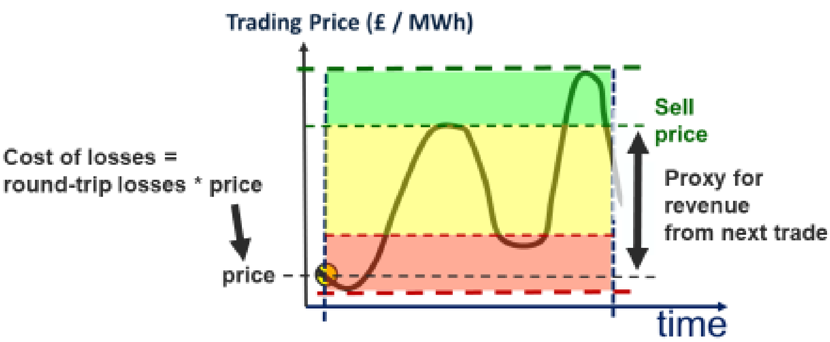


Figure 23 Illustration of "financially viable trade" rule, when price favourable for importing

4.5.2.3. The battery SOC must allow the trade in the envisaged direction

The battery cannot export when it is empty, not import when fully charged.

If	$SOC\ (t-1) > 0$	then	an export trade may proceed	(4.27)
otherwise			an export trade does not proceed	
If	$SOC\ (t-1) < 1$	then	an import trade may proceed	(4.28)
otherwise			an import trade does not proceed	

This logic states whether a trade in the envisaged direction (i.e. import or export) may take place at all. The logic in the following subsection determines whether the SOC might limit the magnitude of the power flow.

4.5.2.4. Magnitude of Power flow P(t)

The battery always exports and imports at full power, whenever its SOC allows.

When exporting

If energy contained in battery:

$$stored\_E_{(t-1)} \geq Pmax\,.\,timestep \tag{4.29}$$

which can be expressed as:

$$SOC_{(t-1)} \geq \frac{timestep}{D} \tag{4.30}$$

(as:

$$\frac{stored\_E_{(t)}}{batt\_energy\_capacity} = \frac{stored\_E_{(t)}}{Pmax.D} = SOC_{(t)} \quad) \tag{4.31}$$

then

$$P\ (t) = Pmax \tag{4.32}$$

At lower values of SOC, the battery fully discharges at this timestep, at lower power:

If

$$SOC_{(t-1)} < \frac{timestep}{D} \tag{4.33}$$

then energy export this timestep, e_out (t):

$$\begin{aligned} e_{out_{(t)}} &= P_{(t)}.timestep \\ &= storedE_{(t-1)} \\ &= SOC_{(t-1)}.battenergycapacity \\ &= SOC_{(t-1)}.Pmax.D \end{aligned} \tag{4.34}$$

and power this timestep, P(t):

$$P\ (t) = Pmax\ .SOC_{(t\ -1)}.\frac{D}{timestep} \tag{4.35}$$

So overall, $$P\ (t) = Pmax\ .\ \min\left(1,\quad SOC_{(t\ -1)}.\frac{D}{timestep}\right) \tag{4.36}$$

When importing

Similarly, the battery imports at full power if there is enough remaining capacity in the battery.

Roundtrip losses are modelled to occur during imports.

If unfilled capacity in battery:

$$\left(\ batt\_energy\_capacity\ -\ stored\_E_{(t-1)}\right) \geq Pmax\ .\ timestep\ .\ \eta \tag{4.37}$$

which can be expressed as: $$(1 -\ SOC_{(t-1)}\ )\ \geq \frac{timestep\ .\eta}{D} \tag{4.38}$$

then $$P\ (t) =\ -Pmax \tag{4.39}$$

At higher values of SOC, the battery fully charges at this timestep, at reduced power.

If $$1 -\ SOC_{(t-1)} < \frac{timestep\ .\eta}{D} \tag{4.40}$$

then $$P\ (t) = -\left(Pmax\ .\ (1 - SOC_{(t-1)})\ .\frac{D}{timestep.\ \eta}\right) \tag{4.41}$$

So overall $$P\ (t) = -\ Pmax\ .\ \min\left(1,\quad (1 - SOC_{(t-1)}\ )\ \frac{D}{timestep\ .\eta}\right) \tag{4.42}$$

4.5.3. Cumulative total energy and overall net revenue values

At every timestep, the overall energy imported and exported during the simulation, and overall net revenue from energy trades (i.e. accumulated cashflow values), are as shown:

total energy delivered (MWh)	*E_out (t)*
total energy imported (MWh)	*E_in (t)*
total accumulated cashflow (£)	*Accum_cash (t)*

where

$$E\_out\ (t) = \sum_{0}^{t} e\_out\ (t) \tag{4.43}$$

$$E\_in\ (t) = \sum_{0}^{t} e\_in\ (t) \tag{4.44}$$

$$Accum\_cash\ (t) = \sum_{0}^{t} cash\ (t) \tag{4.45}$$

Negative values of accumulated cashflows are permitted. (The battery logic allows cashflows below zero, for example following a purchase of electricity at the start of the run. The logic does not force accumulated cashflows to be above zero, though the rule taking into account the cost of round-trip losses avoids most loss-making trades.)

4.6. Model outputs

The model has key outputs at every timestep, and at the end of the simulation run. They are:

4.6.1. Timeseries outputs.

The timeseries of P (t) for the whole simulation is a key output.

Timeseries values of SOC (t) and Accum_cash (t) are also of interest.

4.6.2. Final values at end of simulation

The key final value outputs are: total values of energy delivered (E_out), and energy imported (E_in), and accumulated cashflow (Accum_cash) accrued during the whole simulation run.

The final value of SOC is also important.

The final accumulated cashflow total is adjusted to take into account any SOC difference between the start and finish of the run, using the final wholesale price.

$$\begin{aligned} &Accum\_cash\_adjusted \\ &\quad = Accum\_cash\ (final) + \big(SOC\ (final) - SOC\ (t = 0)\big).Pmax\ .D\ .price\ (final) \end{aligned} \tag{4.46}$$

The number of battery cycles deemed to have occurred, based on total energy transfers, are

$$total\ number\ of\ battery\ cycles = \frac{E\_out\ (final)}{Pmax\ .D} \tag{4.47}$$

Average daily cashflow accrual and battery cycling are as follows:

$$average\ accumulated\ cashflow\ per\ day = Accum\_cash\_adjusted\ .\frac{24}{t} \tag{4.48}$$

$$average\ number\ of\ battery\ cycles\ per\ day = \frac{E\_out\ (final)}{Pmax\ .D}\ .\frac{24}{t} \tag{4.49}$$

where t, run duration, is in hours.

4.7. Battery simulation results: part 1. Base case battery parameters

Initial investigations were performed on the “base case” battery, with parameters:

Pmax = 1 MW, duration = 2 hours, round-trip efficiency = 85%.

Pmax was set at 1 MW as a scalable “unit level”, which could be multiplied as desired for larger batteries.

A “base case” duration of 2 hours was deemed appropriate, considering that Schmidt and Staffell reported median durations of deployed lithium-battery installations of 1.3 hours, with a 25-75 percentile range of 0.7 - 3.8 hours, based on U.S. Department of Energy data [109],

[110]. [109] also suggest a typical round trip efficiency of a lithium ion battery system of around 85%.

4.7.1. Comparison of different trading scenarios by overall net revenue

Simulations were run for all trading scenarios, i.e. all combinations of visibility window and trading strategy, as previously described in Section 4.4.3.

Figure 24 shows how the accumulated net revenue from the simulation (shown as both *total* and *average per day* over the simulation period) varies with the length of the visibility window (2 to 72 hours), for each of the four trading strategies, for the summer, autumn and winter case studies.

A logarithmic x-axis, to base 2, is used to allow clear inspection of the visibility windows relevant to this 2-hour battery, with greatest detail in the range of 2 to 8 hours.

The scenario which yields the highest accrued overall net revenue from the trades – for each case study season and set of battery parameters - is called the "best cashflow" scenario.

The charts in Figure 24 show that for this base case 2-hour battery, good financial results were obtained from simulations using visibility windows of 2 to 4 hours, using all trading strategies, in all three case study seasons. In the winter case study alone, some of the trading strategies also gave good results with visibility windows of 4-8 hours.

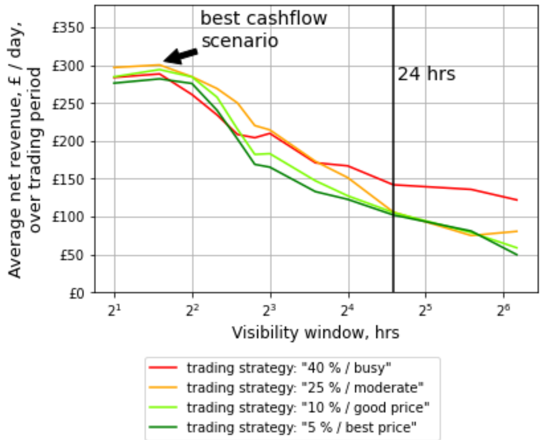
In each season, there was a single highest-performing "best cashflow" scenario, though there were also several other scenarios which yielded similar financial results. In contrast, simulations using longer visibility windows gave much poorer financial performance. This is because the model logic uses the highest and lowest prices occurring during the whole visibility window in setting the "buy price" and "sell price". Thus, a higher or lower price event in the future would more often cause the simulated battery agent to class "now" price conditions unfavourable to trade (as there are better prices in the future). Thus, battery activity generally declines with increasing length of visibility window, and so, usually, does its income.[49]

[49] This feature of the model prevents it from being able to optimise battery activity over a long time trajectory, given extended foresight of pricing data. However, given the restricted foresight of data on real trading platforms, this model is nevertheless considered useful.

(a) Summer – total net revenue

(b) Summer – average daily net revenue

(c) Autumn – total net revenue



(d) Autumn – average daily net revenue

(e) Winter – total net revenue

(f) Winter – average daily net revenue

Figure 24 Variation of net revenue with length of visibility window and trading strategy, base case battery. (a) and (b) Summer; (c) and (d) autumn; (e) and (f) winter case studies. (a), (c) and (e) showing overall net revenue accrual for the whole 35 day case study; (b), (d) and (f) showing average daily net revenue accrual over the case study season.

For all three seasons, the “best cashflow” scenario for the base case battery was the “25% / moderate” trading strategy, shown in orange in the above plots, with a visibility window of 3 hours.

Initially, the “best cashflow” scenarios for the base case battery were examined, as described in the following section. Later, some other trading scenarios (for reduced battery cycling) were investigated, in Section 4.7.4. In Section 4.8 the financial performance of batteries of other durations and round-trip efficiencies is displayed and discussed.

4.7.2. Simulation results – timeseries plots, “best cashflow” scenarios

Battery simulation results for each case study period are shown below. Figure 25 shows timeseries of variables associated with the battery activity, for the whole of the summer case study period. The wholesale price, sell and buy prices are displayed in the top chart; the battery SOC in the middle chart, and overall net revenue (i.e. cashflow accrual) in the bottom chart.

Figure 26 and Figure 27 show timeseries for the same variables during the autumn and winter case studies, respectively.

Battery and trading parameters are shown in Table 19.

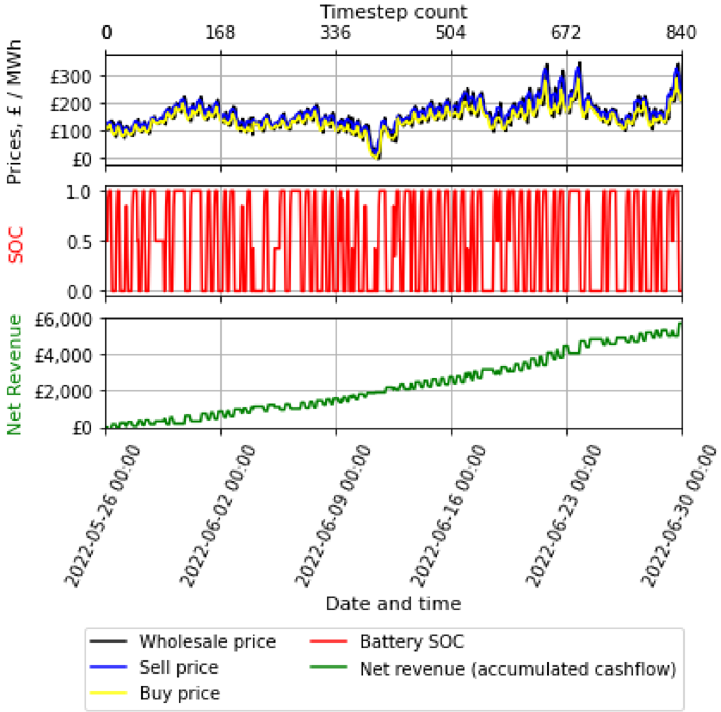


Figure 25 Summer case study (35 days), base case (1MW/2MWh) battery, "best cashflow" scenario. Timeseries of wholesale price, buy and sell prices, battery SOC and overall net revenue (accumulated cashflow). Parameters in Table 19

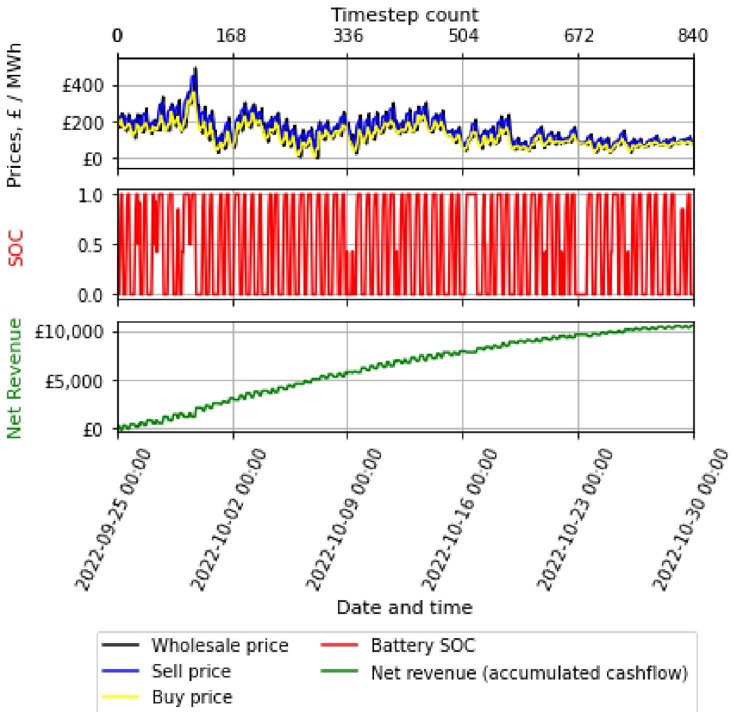


Figure 26 Autumn case study (35 days), base case (1MW/2MWh) battery , "best cashflow" scenario. Timeseries of wholesale price, buy and sell prices, battery SOC and overall net revenue (accumulated cashflow). Parameters as shown in Table 19

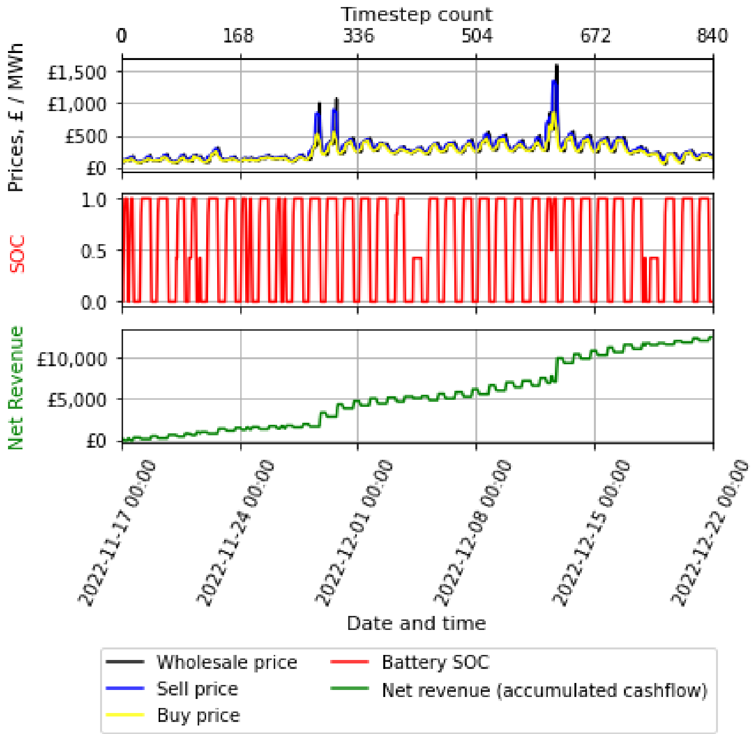


Figure 27 Winter case study (35 days), base case (1MW/2MWh) battery, "best cashflow" scenario. Timeseries of wholesale price, buy and sell prices, battery SOC and overall net revenue (accumulated cashflow). Parameters shown in Table 19

Table 19 Battery simulation results: default battery parameters used

Figure	**Case study season**	**Battery parameters**			**Scenario: Trading parameters**		**Scenario choice criterion**
		Pmax, MW	Duration, hr	Round trip efficiency	Visibility window, hr	Trading strategy	
Figure 25	Summer	1	2	85%	3	"25%" ("moderate")	"Best cashflow"
Figure 26	Autumn	1	2	85%	3	"25%" ("moderate")	"Best cashflow"
Figure 27	Winter	1	2	85%	3	"25%" ("moderate")	"Best cashflow"

Chapter 4 Annex 1 shows the above timeseries, broken down by week, for clearer inspection.

A few examples of single-week plots are shown below in Figure 28 and Figure 29.

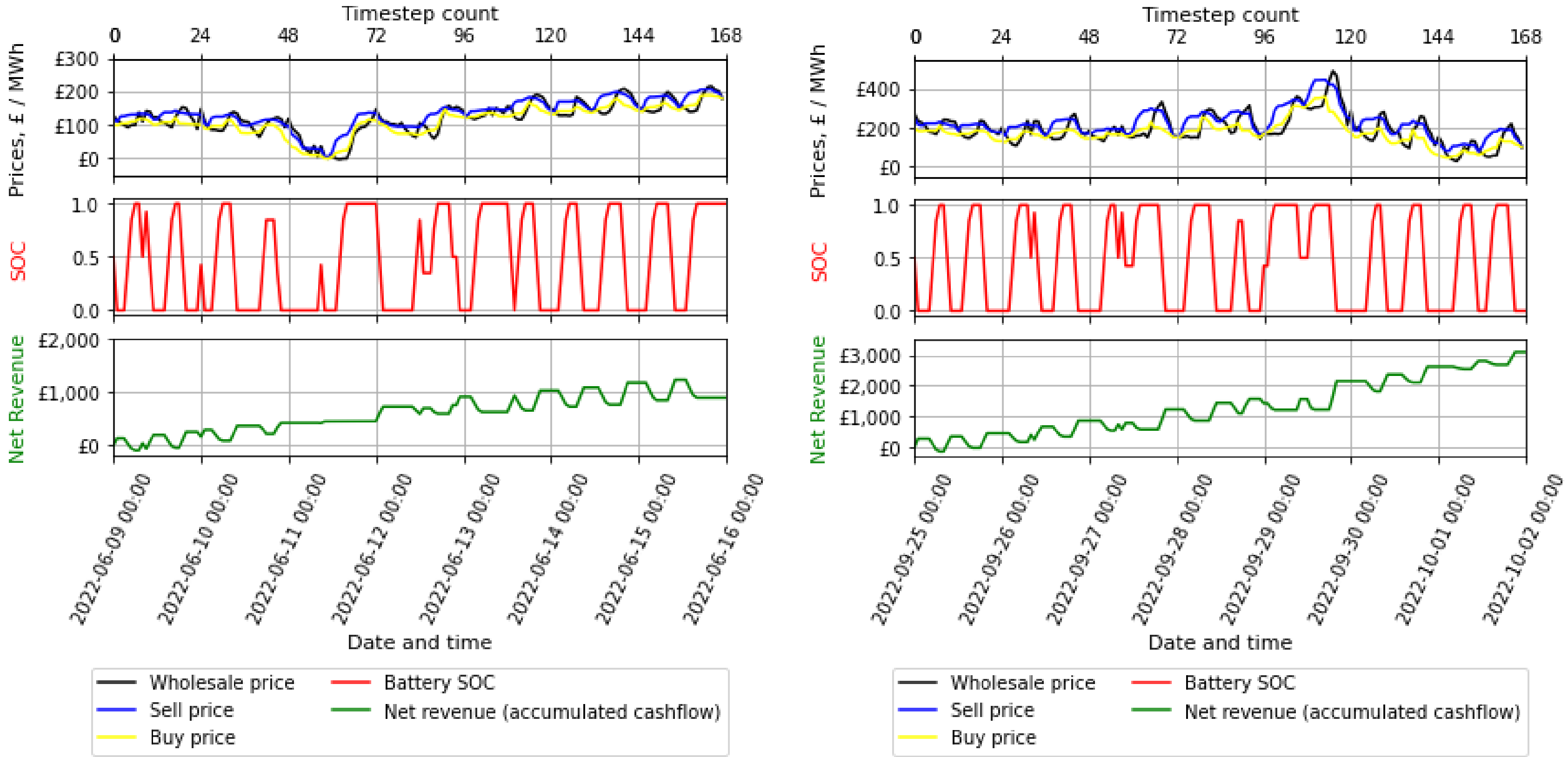


Figure 28 Two 1-week plots of battery simulation – illustrating changeable patterns of cycling. Summer, 3rd week, and Autumn, 1st week, respectively. Base case (1MW/2MWh) battery, "best cashflow" scenario in both cases.

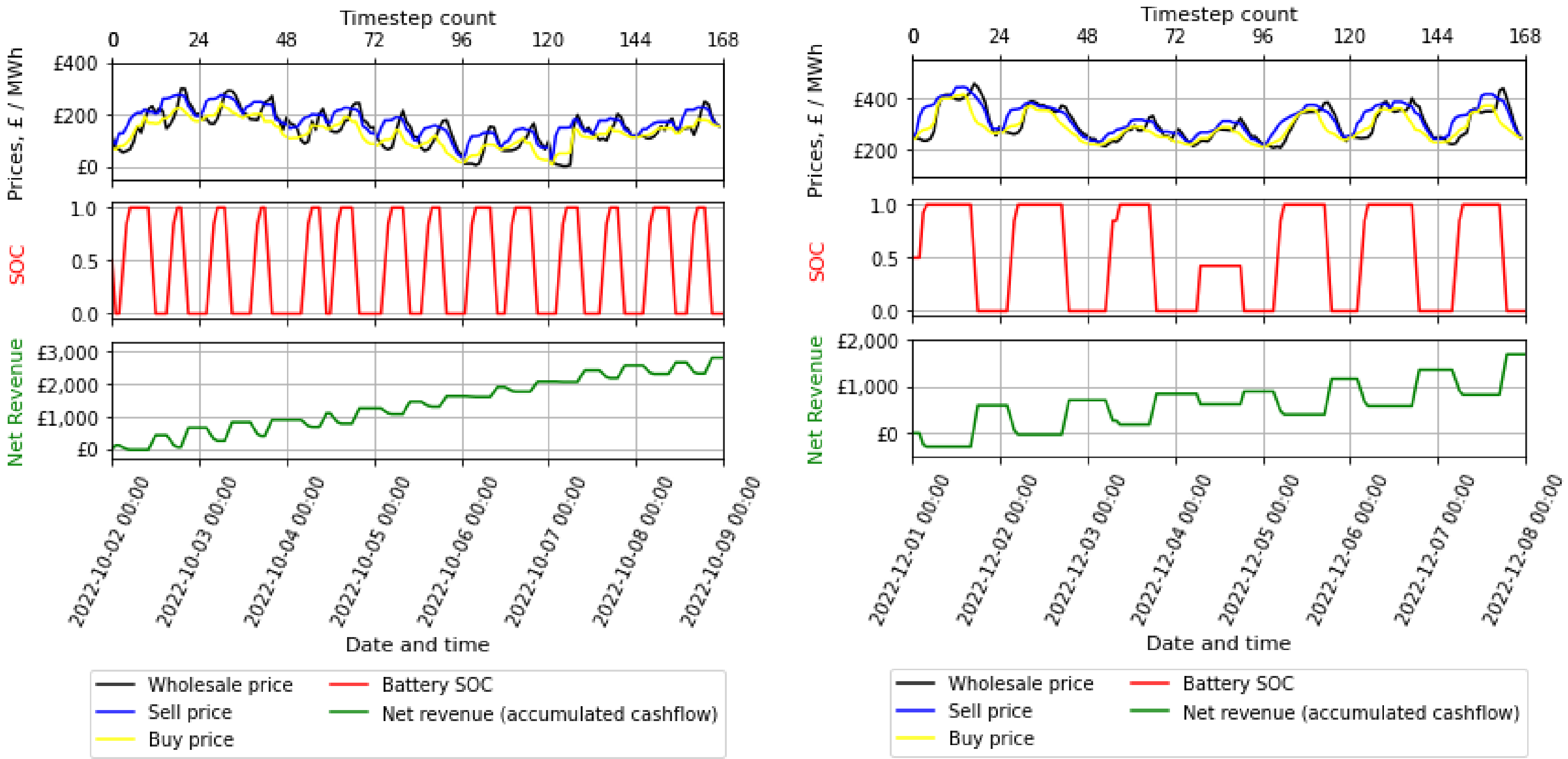


Figure 29 Two 1-week plots of battery simulation – illustrating regular trading patterns. Autumn, 2nd week, regular 2 cycles / day, and Winter, 3rd week, regular 1 cycle/ day. Base case (1MW/2MWh) battery , "Best cashflow" scenarios in both cases.

Figure 28 and Figure 29 allow several observations. First, most of the battery actions are full cycles, i.e. the battery goes from full to empty (requiring 2 timesteps) or vice versa (requiring 2 timesteps at full power and a third at reduced power), such as illustrated in Figure 29, though there are occasions when the battery action will pause while the battery is part-charged or part-discharged, with several such occasions in Figure 28. Second, in summer and autumn, on most days there are around two cycles per day (shown in both above figures). Very occasionally there is more frequent activity; on some days there is only a single battery cycle. Third, in winter, for the first ten days, there are one or two battery cycles per day, but in thereafter, almost every day has a very strong one-cycle -a-day diurnal pattern, for example as shown in Figure 29.

The diurnal pattern, in particular the frequency and times of day at which the battery imports and exports, are discussed in greater detail in Section 4.7.3.

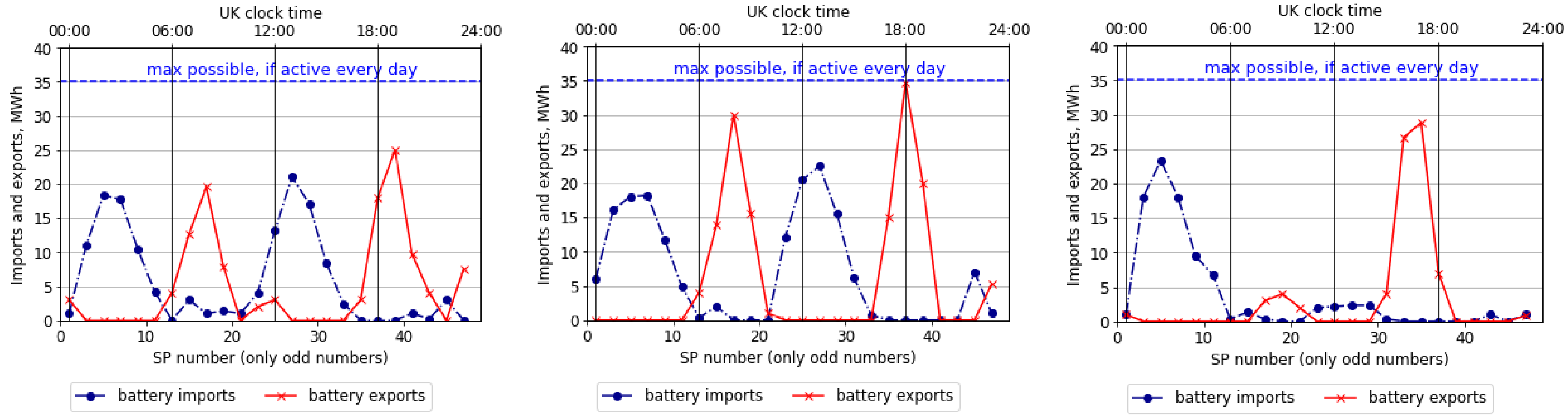
4.7.3. Battery cycling by time of day

The following charts show aggregated actions of the base case battery, under the "best cashflow" scenario, split by Settlement Period (SP)[50] (i.e. by time of day), over the whole of each 35-day case study time period. Plots for the "best cashflow" scenarios for each season are shown below.

As the price data are of 1-hr resolution, the timestep is one hour, and so the plots below can only show odd-numbered SPs.

In the event that the 1 MW simulated battery imported or exported at the same SP every day during the 35-day case study, that import or export peak would touch the "max possible" horizontal line, set at 35 MWh. Import and export peaks at lower levels indicate actions do not occur every day at the same time.

[50] Settlement periods, which last 30 minutes, start at 1, for midnight to 12:20AM, up to 48, for 11:30PM – midnight.



(a) Summer (b) Autumn (c) Winter

Figure 30 Aggregate battery activity by time of day (Settlement Period), over the whole case study. Base case battery, "best cashflow" scenario, parameters as shown in Table 19. (a) Summer, (b) Autumn, (c) Winter case studies

This chart shows that on most days of the summer case study, the simulated battery exported in the morning, around SP 17, at 8am, and also in the early evening, around SP 39 (7pm). Most days there was import activity during the night, most often around 2-3 am, and in the early afternoon. On a few days there was activity at other times.

All case studies show a clear night-time import, and a clear late afternoon or early evening export (the latter peaking at 7pm in summer, 6pm in autumn, and 5pm in winter). Summer and autumn case studies show clear "2-cycles per day" behaviour, with an additional morning export which peaks at 8am; a middle-of-the day import peak is distinct in summer and autumn, peaking at 1pm. In winter, morning exports and midday imports only occurred on a few days over the whole of the simulation.

In all seasons, there is very little activity at other times, though small aggregated exports, occurring on only a few days, are seen in summer and autumn late at night, and in summer only, also around midday. On around 2 days during each case study period, there is an additional import around 7am.

These and similar plots are used later to facilitate comparison between simulated and real batteries, as discussed in Section 4.9.

4.7.4. Other scenarios, with lower battery cycling

The above simulations set no limit to the frequency of battery cycling. The scenarios which yielded the largest overall net revenues ("best cashflow" scenarios) had energy transfers per day as shown in Table 20. For the 1 MW / 2 MWh battery, an energy transfer of 2 MWh / day represents an average of one cycle / day, though it may be achieved from a combination of multiple part-charges.

Table 20 Average daily battery cycles – "best cashflow" scenarios, base case battery

Case study	Average energy delivered per day, MWh	Average no. of battery cycles per day
Summer	3.41	1.7
Autumn	3.98	2.0
Winter	2.21	1.1

Batteries have limited lifetimes, and their long-term performance may be adversely affected by frequent cycling; some battery warranty conditions may stipulate cycling limits or other restrictions in cycling. For example, [213] appears to stipulate an aggregate throughput of energy less than 1 full cycle per day over the battery's 10 year lifetime, for batteries used under some conditions. This section considers the average number of cycles per day of the different simulations.

For the summer and autumn case studies, the "best cashflow" scenarios have approaching 2 cycles per day, on average. This is not surprising, when viewing the timeseries pattern of the trading price (Figure 17): most days, the wholesale price has two peaks a day, morning and early evening. In contrast, the winter case study, the "best cashflow" scenario had just over 1 cycle per day on average. Again, this is not surprising, given that the price timeseries shows a distinct one-peak-a-day pattern – a high price peak in the late afternoon - for much of the case study period.

This work considers “cycling scenarios” approaching or achieving 1 cycle per day as a necessary constraint. The following scenarios, in Table 21, give the best compromise of reducing overall battery cycling to around or at a 1 battery cycle per day, and identifying a battery trading scenario with the highest net revenue which complies with the battery cycling constraint.

Table 21 Battery cycling scenarios. “Best cashflow” and alternative scenarios, with lower battery cycling

Case study season	“Best cashflow”			Second choice “soft” 1 cycle per day limit			Third choice “hard” 1 cycle per day limit		
	Scenario (trading strategy, visibility window)	Av. batt cycles / day	Av. daily net revenue £/day	Scenario (trading strategy, visibility window)	Av. batt cycles / day	Av. daily net revenue £/day	Scenario (trading strategy, visibility window)	Batt cycles / day	Av. daily net revenue £/day
Summer	“25% / moderate”, 3 hrs	1.70	£157	“5% / best price”, 5 hrs	1.18	£137	“10% / good price”, 6 hrs	0.97	£126
Autumn	“25% / moderate”, 3 hrs	1.99	£300	“5% / best price”, 5 hrs	1.18	£241	“10% / good price”, 6 hrs	0.99	£215
Winter [51]	“25 / moderate”, 3 hrs	1.11	£354	“5% / best price”, 4 hrs	1.04	£344	“40% / busy”, 3 hrs	0.97	£351

Figure 31 displays the average energy exports per day, for all trading parameters considered, for the summer, autumn and winter case studies. The horizontal line labelled “battery capacity” is the limit of average daily energy throughput if seeking a scenario in which battery cycling must be limited to around 1 cycle per day on average.[52] Figure 32 is the corresponding chart showing average daily net revenues from all trading scenarios.

[51] In Winter case study, the “hard” 1-cycle per day scenario (“40% / busy”) gives better revenue than the “soft” 1 cycle per day (“5% / best price”)

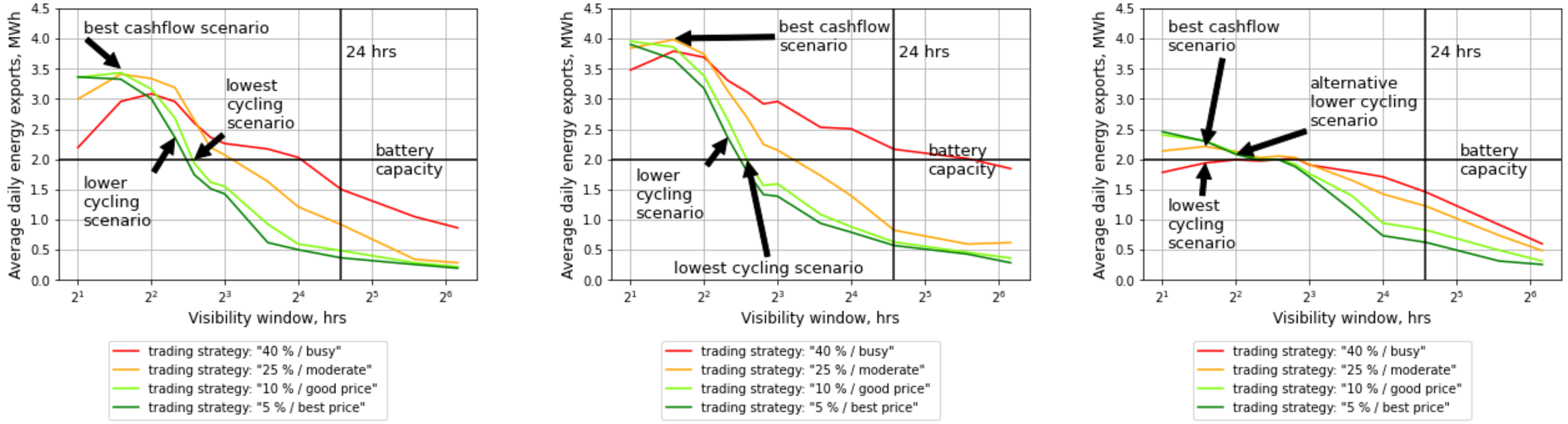
[52] Figure 31 also illustrates that increasing the duration of the visibility window beyond about 4 hours (for a 2-hour battery) results in lower volume of energy transfers. As mentioned in Section 4.7.1, this occurs because a longer visibility window generally has sight of both higher and lower prices, which set the bounds of present price which is favourable for trade. Thus, fewer instances of current price are favourable for trade, and activity declines.

The annotated "best cashflow" scenario for each case study season is as described above. The annotated "lower cycling" and "lowest cycling scenario" (or in winter – "alternative lower cycling scenario") are the scenarios identified in Table 21.

This chart shows that for the winter case study, the "best cashflow" parameters were close to the desired "1 cycle per day" conditions; however for the other two case study seasons, a very different trading scenario would have to be selected to reduce cycling to near to 1 cycle per day. For summer and autumn case studies, reducing the cycling had a significant negative impact on revenue accrual, as shown in Figure 32.

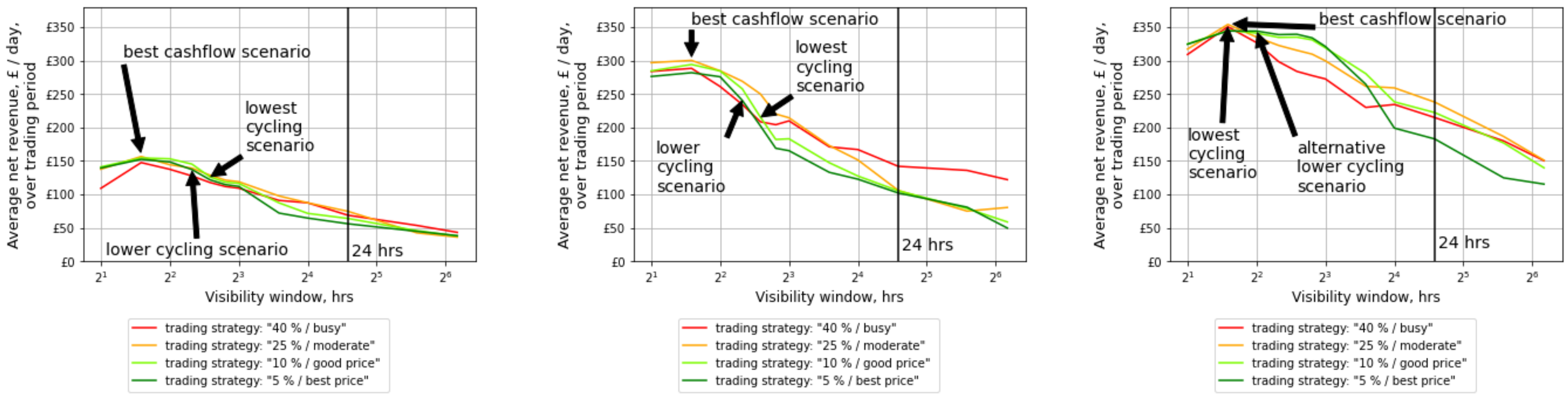
Timeseries charts of battery activity under the "best cashflow" and two lower-cycling scenarios are shown in Chapter 4 Annex 2 Annex 2.1. In summer and autumn there are periods of lower activity in these scenarios, compared to the "best cashflow" scenario. Annex 2.2 shows the plots of battery activity vs SP. These plots show that changing the scenario to reduce cycling reduces the amount of overall activity (i.e. peaks are lower) but the times at which import and export peaks occur do not change.

These three scenarios ("best cashflow", "lower cycling" and "lowest cycling – hard 1 cycle per day limit") are used in the following chapter, which compares simulated battery activity with Scottish wind generation output and windfarm curtailment, and discusses possible effects of batteries on transmission network congestion.



(a) summer (b) autumn (c) winter

Figure 31 Base case (1MW / 2 MWh) battery's average daily energy exports vs length of visibility window, for the four trading strategies. Best cashflow & lower cycling scenarios (a) summer; (b) autumn; (c) winter case studies



(a) summer (b) autumn (c) winter

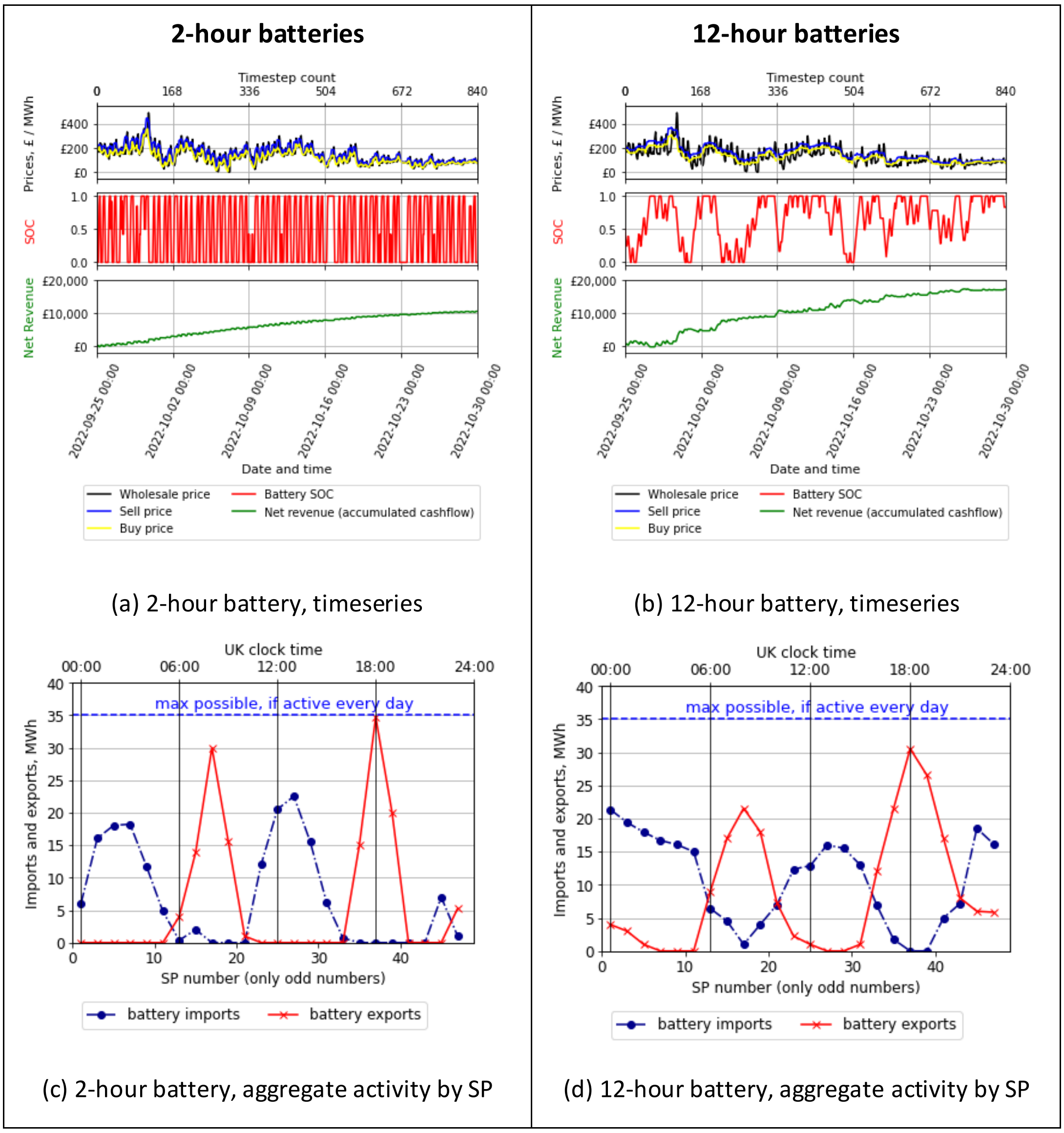
Figure 32 Base case (1MW / 2 MWh) battery's average daily net revenue vs length of visibility window, for the four trading strategies. Best cashflow & lower cycling scenarios. (a) summer; (b) autumn; (c) winter case studies

4.8. Battery simulation results: part 2 – other battery parameters (durations and round trips efficiency values)

4.8.1. Batteries of other durations: 1 hour, 4 hours and 12 hours.

Simulations were repeated for batteries of different durations. For 1-hour and 4-hour batteries, the scenarios which yielded the highest accrued cashflows had broadly similar patterns of battery activity to those of the 2-hour batteries. Different scenarios gave best cashflows: for 1-hour batteries, the "good price" or "best price" trading strategies (requiring prices nearer the maximum or minimum prices within the time horizon of foresight), with short visibility windows of 2-3 hours. For the 4-hour batteries, "moderate" or "busy" trading strategies gave the highest overall cashflows, in every case with a slightly longer visibility window of 4 hours.

Batteries of 12-hour duration had very different patterns of behaviour, with full emptying and full recharging occurring only a few times during each case study; the "busy" trading strategy and visibility window around 10 hours gave highest simulated accrued cashflow. Timeseries plots of price, battery activity and cashflows for batteries of duration 1 to 12 hours are shown in Chapter 4 Annex 3 (plots (a) to (d) for each case study season), with examples of results for autumn and winter shown below in Figure 33 and Figure 34. Chapter 4 Annex 3 also contains plots of battery activity by time of day for the same batteries. These found the same general diurnal pattern of activity for batteries of all durations, though activity peaks were broader for longer duration batteries. In the case of winter case study, 12-hour batteries alone showed significant export activity during the morning and daytime in addition to the principal export time in late afternoon.



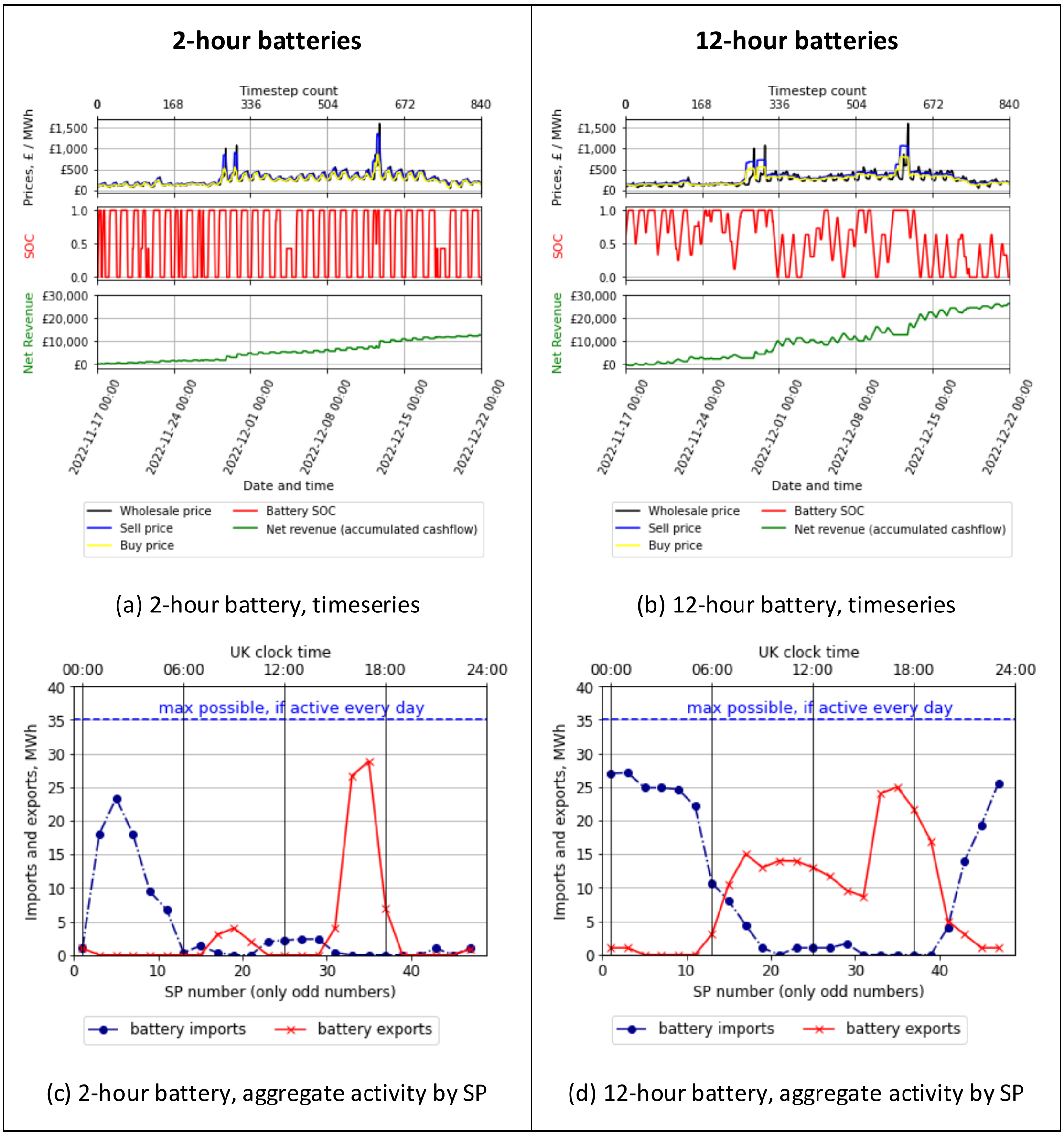
(a) 2-hour battery, timeseries

(b) 12-hour battery, timeseries

(c) 2-hour battery, aggregate activity by SP

(d) 12-hour battery, aggregate activity by SP

Figure 33 Comparing 2-hour and 12-hour battery simulations. Autumn case study. Both batteries 85% round-trip efficiency. Plots of timeseries, and of aggregate activity by Settlement Period



(a) 2-hour battery, timeseries

(b) 12-hour battery, timeseries

(c) 2-hour battery, aggregate activity by SP

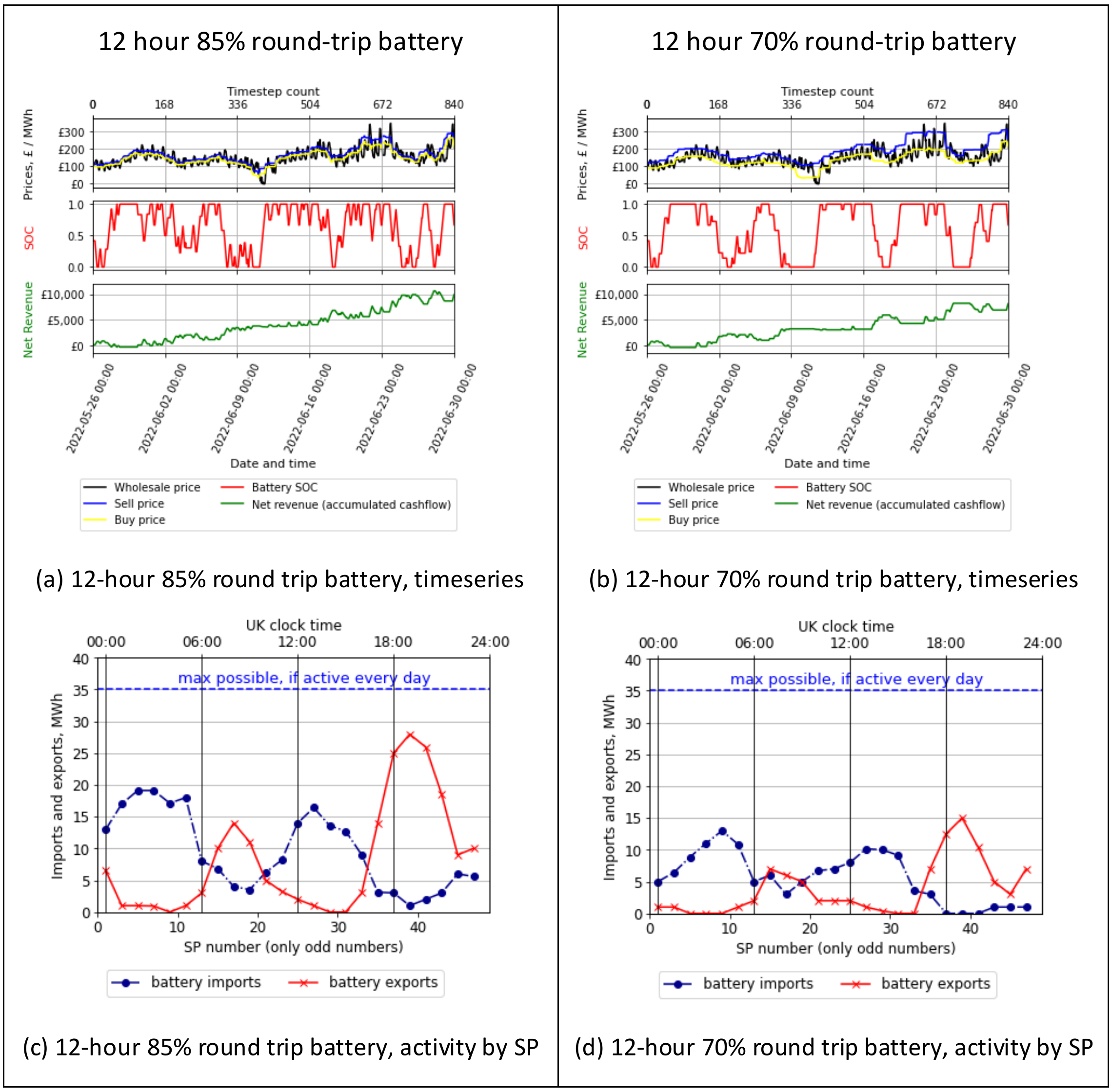
(d) 12-hour battery, aggregate activity by SP

Figure 34 Comparing 2-hour and 12-hour battery simulations. Winter case study. Both batteries 85% round-trip efficiency. Plot of timeseries, and of aggregate activity by Settlement Period

4.8.2. Effect of increasing cycling losses

Because the model only allows trades to proceed if their expected income at least covers the cost of round-trip losses, as described in Section 4.5.2.2, increasing round-trip losses would be expected to reduce the activity of the simulated battery, as with higher losses, more of the trades – especially with a small difference between buy and selling prices, or when the price at which electricity is purchased is high - are classed as financially unviable, and so not allowed.

For the 12-hour batteries, simulations were performed with the 85% round trip, and also with 70% round-trip efficiency, the latter considered more representative of likely behaviour of a flow battery. This increase in losses has significant effect on the battery's simulated behaviour. Simulated battery cycles were less frequent, about once per week. The scenarios giving the best cashflow totals were in almost every case the "busy" trading strategy, with much longer visibility windows of around 10 or around 20 hours in most cases. The timeseries are plotted in Chapter 4 Annex 3 plot (e) for every case study season. Figure 35 shows an example from the summer case study period.



(a) 12-hour 85% round trip battery, timeseries

(b) 12-hour 70% round trip battery, timeseries

(c) 12-hour 85% round trip battery, activity by SP

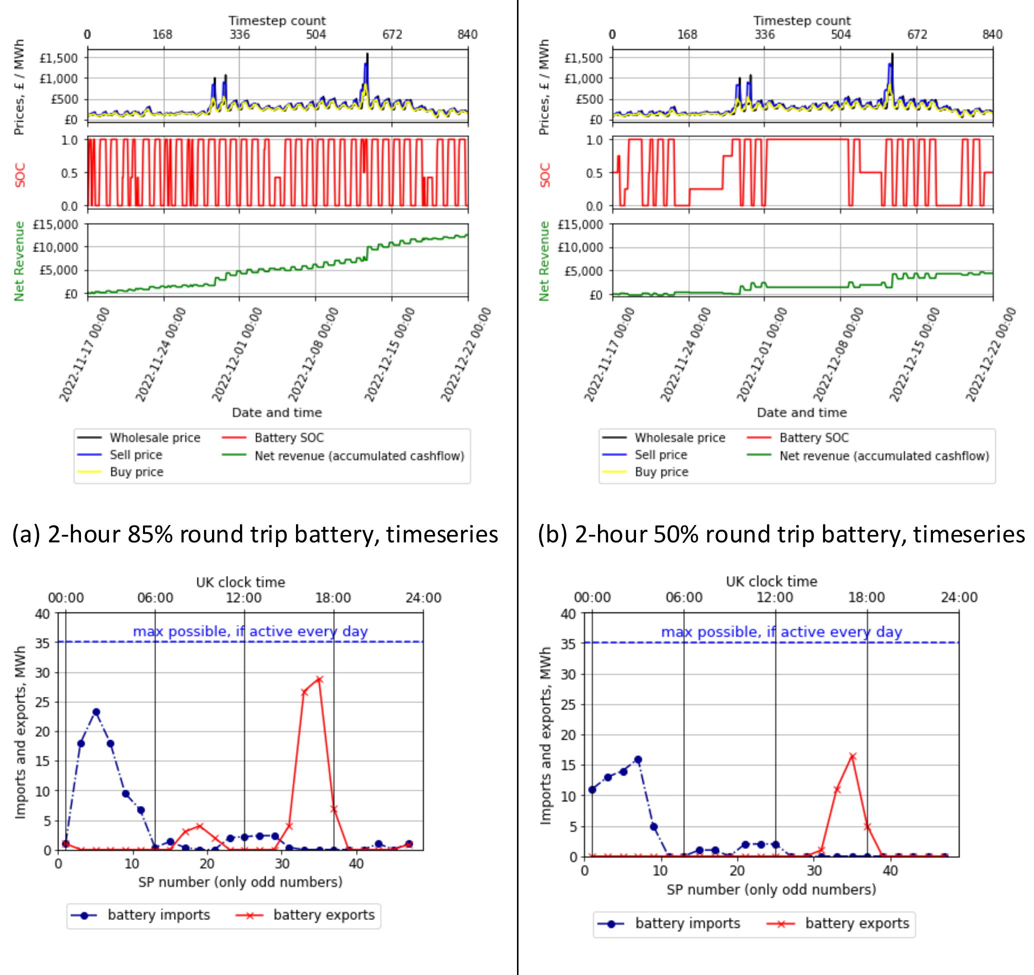
(d) 12-hour 70% round trip battery, activity by SP

Figure 35 Summer case study. Effect of round-trip efficiency on activity of 12 hour battery, "best cashflow" scenario. Plots of battery activity timeseries, and activity by Settlement Period, for 85% and 70% round-trip batteries.

For the short duration (2 hour) batteries, batteries of lower round trip efficiencies (70%, 60% and 50%) were modelled for the winter scenario, and compared to the base case battery of 85% round-trip efficiency. The results are shown in full in Chapter 4 Annex 3, Annex 3.4, with two examples shown below in Figure 36. These charts show that on some days, the battery behaves in a similar way at all values of round-trip efficiency. However, the battery with higher losses has days of inactivity, the number of which increases with round-trip losses. The plot of activity by time of day shows similar generic diurnal pattern for batteries of all round-trip efficiency values, though the frequency of activity declines as losses increase.

2 hour 85% round-trip battery

2 hour 50% round-trip battery



(a) 2-hour 85% round trip battery, timeseries

(b) 2-hour 50% round trip battery, timeseries

(c) 2-hr 85% round trip battery activity by SP

(d) 2-hr 50% round trip battery, activity by SP

Figure 36 Winter case study. Effect of round-trip efficiency on activity of 2 hour battery, “best cashflow” scenario. Plots of battery activity timeseries, and activity by Settlement Period, for 85% and 50% round-trip batteries.

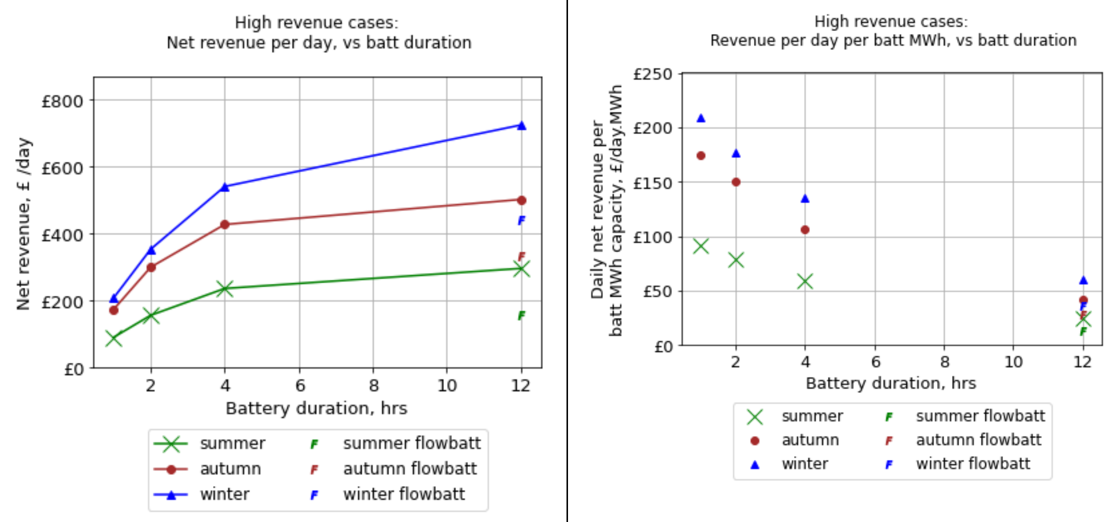
4.8.3. Effect of battery duration on cashflows

Table 22 lists the overall net revenues (accumulated cashflows) from batteries of different duration, as net revenue per day, and as net revenue per day per MWh of battery capacity. All values are for "best cashflow" battery cycling scenarios. In Chapter 4 Annex 4 a similar table, including battery trading parameters, and with corresponding values for "lowest cycling" as well as "best cashflow" scenarios.

Table 22 Battery net revenues for different battery durations. Best cashflow scenarios, all seasons.

Case study season	Battery parameters		Results		
	Duration, hrs	Round -trip	Net revenue (accumulated cashflow) average £/ day over the whole case study season	Net revenue (accumulated cashflow) per MWh batt capacity, average £/ day. MWh	Battery cycling: Average battery cycles / day
summer	1	85%	£91.15	£91.15	1.85
	2	85%	£156.74	£78.37	1.70
	4	85%	£236.78	£59.20	1.39
	12	85%	£296.65	£24.72	0.46
	12	70%	£156.62	£13.05	0.22
autumn	1	85%	£174.63	£174.63	2.12
	2	85%	£300.36	£150.18	1.99
	4	85%	£427.89	£106.97	1.52
	12	85%	£502.50	£41.88	0.51
	12	70%	£334.95	£27.91	0.31
winter	1	85%	£208.97	£208.97	1.19
	2	85%	£354.08	£177.04	1.11
	4	85%	£541.23	£135.31	0.94
	12	85%	£724.75	£60.73	0.50
	12	70%	£441.16	£36.76	0.26

Figure 37 (a) shows the net revenue per day of a 1 MW battery, for each of the case study seasons, and its variation with battery duration, selecting the "best cashflow" scenarios only. All points have 85% round trip efficiency except for the "flow battery" points, labelled "F", which have 70% round trip efficiency. ("Flow batteries" are only modelled as having 12 hour duration.) This chart illustrates how battery net revenues increase with increasing battery duration, but that the increase diminishes with increasing battery duration. It also illustrates how net revenues varied considerably between the case study seasons. Figure 37 (b) shows how the daily net revenue per MWh of battery capacity declines steeply with increasing battery duration. These results are remarkably consistent across the three case study seasons, despite the large differences in net revenue values themselves.

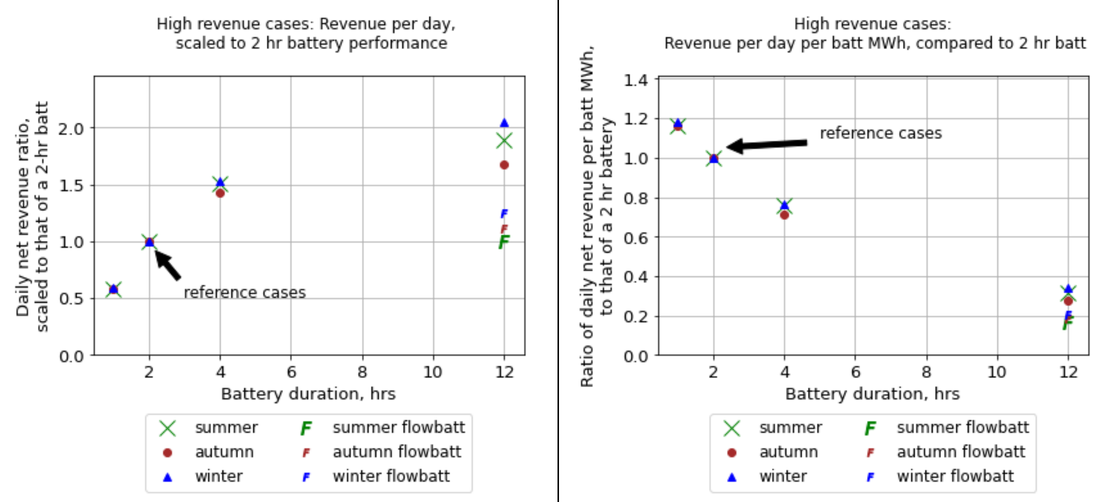


(a) Daily net revenue vs battery duration

(b) Daily net revenue per MWh battery capacity vs battery duration

Figure 37 Battery net revenues vs battery duration. Batteries 1-12 hours, 85% η; & "Flow battery": 12 hours, 70% η. "Best cashflow" scenarios. (a) average daily net revenue (£/day) vs battery duration; (b) average daily net revenue per MWh of battery capacity vs battery duration.

Figure 38 is a similar plot, but all values are scaled to the applicable results (i.e. average daily net revenue, or average daily net revenue per MWh of battery capacity) for a "base case" 2-hour duration battery.



(a) Daily net revenue vs battery duration

(b) Daily net revenue per MWh battery capacity vs battery duration

Figure 38 Ratio of battery net revenues to those of a 2-hour battery, vs battery duration. Batteries 1-12 hours, 85% η; & "Flow battery": 12 hours, 70% η. "Best cashflow" scenarios. (a) average daily net revenue vs battery duration; (b) average daily net revenue per MWh of battery capacity vs battery duration.

These charts show that accrued cashflows increase with battery duration, but the increase is not linear. For example, a 4-hour battery would only make around 50% more revenue than a 2-hour battery (Figure 37a). A 1-hour battery would perform around 20% better, in terms of revenue per MWh, than the 2-hour battery (Figure 38 b); a 4-hour battery would accrue around only 75% of the net revenue per MWh of a 2-hour battery, and a 12-hour battery (of 85% round trip efficiency) only about 30% of the net revenue per MWh of a 2-hour battery (Figure 38 b). A 12-hour battery of 70% round trip efficiency would make a similar accumulated cashflow to a 2-hour battery of 85% round trip efficiency (Figure 37a). These results hold for all case study seasons. These generic results – that increasing battery duration brings diminishing returns: arbitrage income *per kWh* of battery energy capacity *decreases* as battery duration *increases* - are also reported in [95].

Chapter 4 Annex 4 also includes corresponding graphs for "lowest cycling" scenarios. These results are similar to the "best cashflow" results presented above, but with slightly diminished effect of "higher net revenues per MWh for shorter duration batteries". This reduced effect is likely to be because limiting battery cycling to 1 battery cycle per day significantly reduces the net revenues of 1 hour and 2 hour batteries, has a small effect on those of 4 hour batteries (summer and autumn only) and no effect on 12 hour batteries.

It is clear that an owner of multiple short-duration batteries would make significantly higher revenues by operating the batteries coincidentally than sequentially. This particularly applies to 12-hour batteries, of which much of the stored energy was "redundant" for large durations of the case study periods.

4.9. Validation: comparison with "real batteries" in GB

4.9.1. Overview

As described earlier in Chapter 3, 2022 BM data list 23 battery units which participated in wholesale trading during 2022. Of these, most commenced activity during 2022, and 21 had activity during one or more of the case study periods, with more batteries becoming active later in the year.

Many of the batteries engaged in only low-power trades (i.e. of power significantly lower than their maximum FPN that year), and some solely or predominantly in either imports or exports, during part or even all of their active periods, as illustrated in Chapter 3 Annex 4, examples including Roosecote, Port of Tyne, Kemsley and Pen y Cymoedd batteries. However, others had distinct short-duration import and export activities, at least some of the time, which are compared with battery simulations below.

Neither the maximum power, nor the duration, of any of the batteries is known for certain. For maximum power, the larger value of the maximum import or export that occurred during 2022 is taken to represent *Pmax*. Regarding duration, many exhibit short duration peaks consistent with a duration of around 2 hours, (or in some cases, lower-power activities for a few hours) and this is the battery simulation against which they are compared.

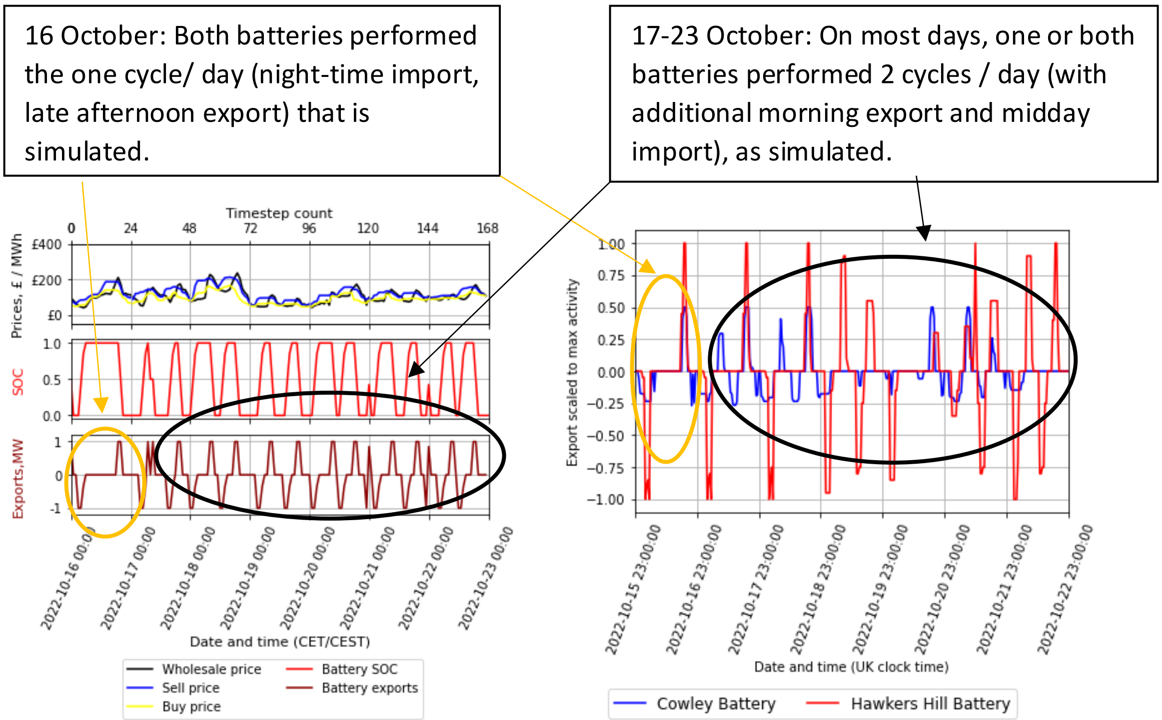
4.9.2. Timeseries plots

Several of the batteries engaged in imports and exports once or twice a day, some of which were at or approaching full power (for that battery)[53], some of which were of lower power, as illustrated in Chapter 3 Annex 4. Some batteries engaged in trades on some days but not others, while others on some days had numerous trades.

Some of the batteries had patterns of imports and exports which were reasonably close to the battery model simulations, examples of which are shown in Figure 39 (autumn, most days 2-cycles/ day) and Figure 40 (winter, most days 1 cycle/ day). In both examples, both simulated and selected real batteries engaged in night-time imports and early evening exports every day, and on some days, also an additional export in the morning, and an import in the middle of the day. Other examples are shown in Chapter 4 Annex 5, which shows a mixture of batteries with similar and different patterns of activity.

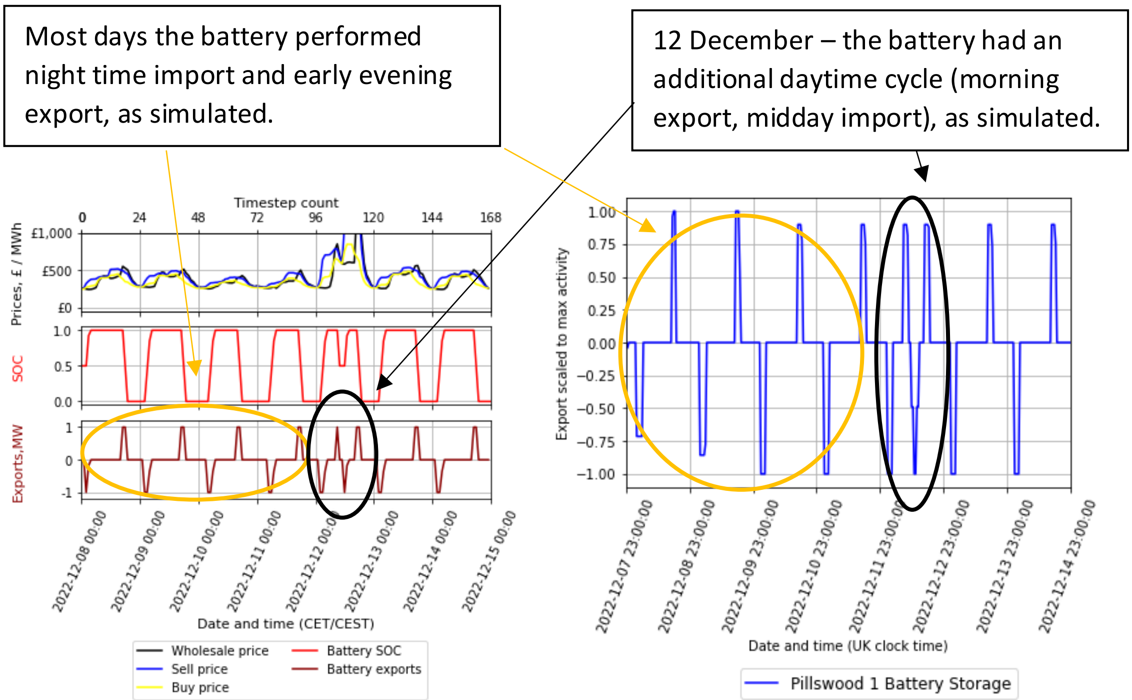
In all cases, the real battery FPNs are scaled to their maximum FPN (the larger of max import or max export) that occurred during 2022.

[53] Full power for a BMU battery is taken here as the magnitude of the larger of its highest FPN import or export during 2022. The interested reader is directed to the previous introduction of these data in Section 3.3.3.



(a) (b)

Figure 39 Autumn case study, week 4. Comparison of (a) battery simulation, and (b) Cowley and Hawkers Hill batteries FPNs (scaled to max output)[54]



(a) (b)

Figure 40 Winter case study, week 4. Comparison of (a) battery simulation, and (b) Pillswood 1 battery FPNs (scaled to max output)

[54] Battery simulations are in European time (CET / CEST) as the timezone of the price data, 1 hour ahead of UK clock time. Thus, the time 00:00 for the battery is the same as 23:00 for the actual batteries.

4.9.3. Activity by Settlement Period – a few individuals

Aggregate activity of the batteries, displayed by Settlement Period, was prepared, showing similar plots to those in Section 4.7.3., with two examples below shown in Figure 41 and Figure 42, below.

For some of the batteries, the pattern of battery activity by SP for a case study season is similar to that in the battery simulations.

For the real batteries, for both import and export, for each 35-day case study season:

$$\begin{aligned} &aggregate\ power\ flow\ (case\ study\ season, SP) \\ &\qquad = sum\ of\ all\ MW flows\ over\ the\ 35\ days\ (SP) \end{aligned} \tag{4.50}$$

$$Pmax = \max\left(\max(MW\ import, 2022), \max(MW\ export, 2022)\right) \tag{4.51}$$

$$maximum\ possible\ aggregate\ import\ or\ export\ (SP) = Pmax * 35 \tag{4.52}$$

So $battery\ activity\ as\ a\ fraction\ of maximum\ possible\ (import, export, SP)$

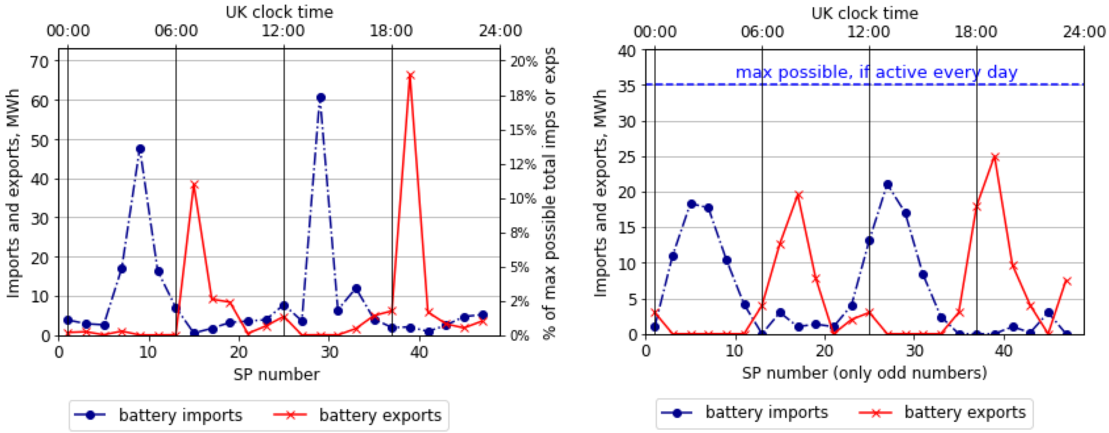
$$\begin{aligned} &= \frac{aggregate\ powerflow(SP)}{maximumpossible\ aggregte\ powerflow} \\ &= \frac{aggregate\ powerflow(SP)}{Pmax * 35 days} \end{aligned} \tag{4.53}$$

In Figure 41 and Figure 42, the battery activity have been smoothed from half-hour to 1-hour resolution, for better comparison with the simulation, which is has 1-hour timesteps.

Similar charts for other grid-connected BMU batteries are displayed in Annexes to Chapter 4 Annex 6.

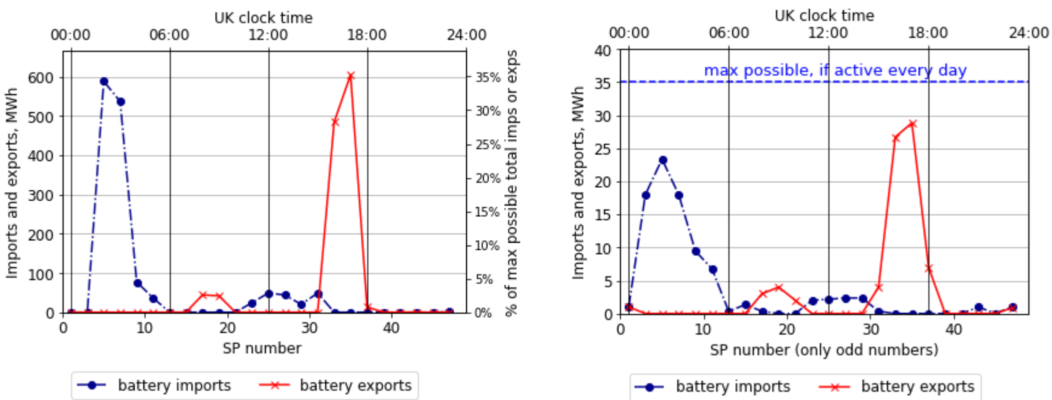
These charts show clear pattern of night-time imports and late afternoon / early evenings exports on most days, in all seasons. The summer and autumn examples show additional morning export and midday imports on most days.

The times of day at which these batteries' imports and exports occurred, and number of times per day of such energy flows, were broadly in agreement with the energy flows simulated for 2 hour batteries.



(a) (b)

Figure 41 Summer: aggregate imports and exports by SP, (a) Pen y Cymoedd battery (1-hour resolution), and (b) 2-hour battery simulation (highest revenue scenario) as shown in Figure 30



(a) (b)

Figure 42 Winter: aggregate imports and exports by SP, (a) Pillswood 1 battery (1-hour resolution, as shown above in Figure 40), and 2-hour battery simulation (highest revenue scenario) as shown in Figure 30

The main difference between the real batteries and the simulations is the volume of aggregate import and export over the 35 days is much lower, compared to the simulated values. Many real batteries had days or weeks of low activity, or were active at lower than full power, for much or all the time. (This observation of BMU batteries is illustrated in the battery timeseries charts, displayed in the previous chapter, Chapter 3 Annex 4. Reasons could include engagement in other activities, or differences in business models, or technical or financial constraints, which may include degradation avoidance. The range of activities seen and options for BMU batteries in 2022 was introduced in Section 3.3.3 and discussed briefly in Chapter 3's conclusion, Section 3.7.)

4.9.4. Activity over time of day – batteries

An analysis of plots, as above, of all batteries was made, comparing the main import and export actions, and the time of day they normally occurred at.

Some batteries were initially eliminated from this analysis, for reasons of a large imbalance between volume of import and export FPNs, and others because of having BM trades comparable or exceeding the FPN volumes, as tabulated in Table 23 with further details in Annexes to Chapter 4 Annex 7.

Table 23 Number of GB batteries active during 2022 case study seasons

Case study season	Number of batteries with some activity	Number of batteries eliminated from further study: FPNs (MWh) of imports and exports differed by over a factor of 5	Number of batteries retained for further study
Summer	14	9	5
Autumn	13	4	9
Winter	21	4	17

There are some differences between simulations and real batteries, principally in winter, with over half of the real batteries engaging in daytime import, which were simulated to occur only occasionally, in addition to the evening export and night time import. A minority of real batteries also engaged in imports or exports at other times, in all seasons, which are simulated to rarely occur.

Nevertheless, there is good enough agreement between enough features to have confidence that this simulation is a reasonable expression of activity that a battery could realistically engage in.

Table 24 shows that there is generally good agreement between the broad diurnal patterns of battery activity in real batteries, and in the simulations.

There are some differences between simulations and real batteries, principally in winter, with over half of the real batteries engaging in daytime import, which were simulated to occur only occasionally, in addition to the evening export and night time import. A minority of real batteries also engaged in imports or exports at other times, in all seasons, which are simulated to rarely occur.

Nevertheless, there is good enough agreement between enough features to have confidence that this simulation is a reasonable expression of activity that a battery could realistically engage in.

Table 24 Comparison of simulations with real battery behaviour: activity by SP

Diurnal activity features	Simulations			Numbers and percentages of real batteries whose actions agreed with the simulated feature (or absence of feature)					
Time of day	Summer	Autumn	Winter	Summer		Autumn		Winter	
				Total no. batts = 5		Total no. batts = 9		Total no. batts = 17	
				No.	%	No.	%	No.	%
Night-time import	Strong peak	Strong peak	Strong peak	5/5	100%	9/9	100%	17	100%
Morning time export	Strong peak	Strong peak	Slight peak	5/5	100%	9/9	100%	15	88%
Daytime import	Strong peak	Strong peak	Min-imal activity	5/5	100%	7/9	77%	4	24%
Late afternoon/ early evening export	Strong peak	Strong peak	Strong peak	5/ 5	100%	9/9	100%	17	100%
Other import	Very little	Very little	Very little	4/5	80%	8/9	89%	14	82%
Other export	Very little	Very little	Very little	3/5	60%	6/9	67%	13	76%

4.10. Discussion

4.10.1. The model, its limitations, and possible improvements

There are numerous different approaches to modelling the behaviour of a battery, as described in Section 4.2. The use of an agent-based formulation has facilitated the running of multiple scenarios, from which a small selection has been chosen to illustrate examples of choices a rational battery agent might make. As this study concerns wholesale trades only, which occur over a matter of hours and days, the simplifications of the power-energy model are much less critical than for studies of battery actions over much faster timescales, such as provision of a fast frequency response service, or a combination of trades and faster services.

There are limitations of this model. A major one is that it runs with fixed battery parameters for a whole simulation. In the winter case study especially, there were several distinct and different patterns of wholesale price, during which different battery trading parameters (visibility window, trading strategy) may have yielded better net revenues. Functionality to change battery parameters during a run would be a useful improvement to add to the model, if work was to be continued.

A second limitation is that the battery trades as soon as the price is “favourable”, compared to prices over the next few hours, or whatever length of visibility window is used. In particular, with short visibility windows, prices may become “more favourable” a little later, especially concerning imports during the night, during which prices tend to be low for about 6 hours. Thus, a short-duration battery may import early in the night, and be unable to take advantage of later, slightly better prices. However, high price events tend to be of short duration, often around two hours, in the late afternoon or early evening, during which immediate full-power export would normally be most financially rewarding approach. The “best cashflow” scenario is the one with aggregate best net revenues, and may be sub-optimal for either or both of imports or exports. Introduction of different trading parameters governing purchases and sales of electricity might slightly improve cashflows.

The trading strategies, enabling instructions to trade at discrete fractions of “market price gap”, are selected from a choice of four fractions. An optimisation algorithm would probably find a combination of trading strategy and visibility window that lies between those investigated here. For the 2-hour duration batteries, the small difference in accrued cashflow between several of the better scenarios suggests that the very “optimal” trading scenario would be little different to the “best cashflow” scenario chosen. The fact that the resultant “best strategy” describing appetite for trading, is one of the “mid-range” strategies (i.e. not “busy”, nor “wait for best price” trading strategies, but an intermediate strategy, “moderate”, as described in Section 4.4.3) also gives confidence that an “optimum cashflow” scenario would not differ greatly from the “best cashflow” scenarios chosen here. In contrast, however, results for 12-hour battery in most cases found best cashflows with the “busy” trading strategy, instructing buying and selling at prices <=40% and >= 60% of the market price gap, respectively. For such longer duration batteries (or other storage assets), further work could investigate other trading strategies, with buying instructed between 25% (the “moderate” strategy”) and 50% (not investigated), to seek possible improvements in net revenues.

A key limitation of this work is that little is done to include the effects of any ongoing degradation, or battery actions to avoid it. With batteries having an expected lifetime of several years, little degradation is expected to occur within the space of a 5-week case study investigated here, so the above results are considered valid. However, a longer term study, over a year or more, ought to factor in likely reduction in function. Regarding possible operational choices seeking to reduce degradation, this work has included the sensitivity of a "less cycling" strategy, which has approaching only a single cycle per day on average. Further work investigating other approaches to degradation avoidance would be useful.

Nevertheless, despite all limitations, the reasonably good agreement between the simulations and some of the real batteries in Section 4.9 gives further confidence that this model is adequate to give a network or system operator an indication of the kinds of actions it could expect from batteries.

A further point to note is that this work is all done on hourly resolution day ahead price data. Real batteries can choose which platforms to trade in, including half-hourly duration in-day markets. A brief study of sections of the winter case period, during which limited data from in-day platforms were also available, suggested that slightly higher revenues could be made on in-day, as opposed to day-ahead markets, but there was a risk – such as one occasion when a major price spike was absent from one of the in-day platforms[55]. So in short, these results *may slightly* under-estimate potential battery cash flows, for batteries able and choosing to use other platforms.

4.10.2. Behaviour of a rational battery, engaged in wholesale trades

In all cases, the trading strategy was identified which resulted in the highest overall net revenue, for the battery of given parameters, for a single season. This would appear to be the activity a rational battery would undertake, if engaging in wholesale trades. In several cases, however, simulations for a particular battery and season using several different trading strategies yielded similar financial results, but with some differences in battery actions. A rational battery could opt for any of these: potentially a slight reduction in cycling behaviour, or perhaps uncertainties in prices, may make slightly lower cashflow scenarios of greater overall benefit. Thus, there is not always a single answer for expected battery behaviour. The

[55] There was a major price spike around 5pm (UK time) on 28 and 29 Nov 2022: present on Nordpool and EPEX's day-ahead auction, and EPEX's intraday auction platforms, but absent on EPEX's continuous intraday trading platform.

availability of multiple trading platforms with slight price differences introduces further scope for differences in battery activity.

However, both simulated and real batteries' actions showed a strong diurnal pattern, with night-time imports and early evening exports of energy most days. During the summer and autumn case studies, an additional morning export and midday / early afternoon import of energy occurred on many days. This pattern was robust in battery simulations across all battery durations, round-trip efficiencies, and scenarios of limited battery cycling investigated, though batteries with greater losses, or limitations on cycling frequency, did not trade every day. Similar patterns were observed for many of the real grid-connected batteries, though with examples of real batteries performing both 1-cycle-a-day and 2-cycles-a-day at all seasons.

If seeking to restrict battery cycling rates to protect battery long-term health, or to comply with warranty conditions, activity with less frequent cycling may be desirable, even when it would accrue lower overall net revenue. For the summer and autumn case study seasons, with a wholesale price pattern of "2 peaks per day" on many days, any need to reduce cycling of the batteries to around 1 cycle per day on average would reduce cashflows compared to the "best cashflow" scenario, and would result in a significantly different pattern of battery behaviour. This was much less the case during the winter case study, when the wholesale price pattern was "2 peaks a day" on some days but more often "1 peak a day". If overall cycling is to be limited, incomes might be maximised by allowing high cycling rates at times of high price volatility, for example early in the autumn case study period, and to restrict or abstain from trading at other times, for example during the summer case study period, when in-day price variations were much smaller, and much smaller overall revenues could be accrued. Depending on the battery business model and requirements for a steady cash-flow, even differences in battery behaviour from year to year could be advantageous, such as allowing greater activity during a year with more volatile prices (such as 2022) and restricting activity during years of relatively calm prices (for example, 2020). Such a strategy inevitably would entail risk of inaccurate forecasts of future wholesale prices.

Actions of batteries of 1-4 hours' duration, were broadly similar to one another at each season (viewing "best cashflow" scenarios), but those of 12-hour duration batteries (intended to represent a flow battery) had significantly different patterns of actions.

Simulated financial returns from a battery engaged in wholesale trades are greatest, per MWh of battery energy capacity, for batteries of the shortest duration (1 hour), as shown in Section 4.8.3. Thus an owner of multiple 1-hour or 2-hour batteries would gain greater returns by operating them coincidentally rather than sequentially. If it is a system need to have storage assets of 4 – 12 hour duration, this investigation suggests that wholesale trades alone may not be lucrative, unless their O&M and financing cost per MW is within 150% - 200% that of 2-hour batteries (as shown in Figure 38 and

Table 22), assuming batteries can cycle twice a day and earn "best cashflow" scenarios.

The financial advantage of using 1-hour or 2-hour batteries, rather than of longer duration[56], is less pronounced in scenarios where cycling is restricted, as shown in Chapter 4 Annex 4, Figure 144 and Figure 145, which display battery revenues vs battery duration.

Assuming the round-trip efficiency parameters for solid (representing lithium ion or similar) and flow batteries to be as modelled (85% and 70% respectively, including ancillary equipment) a 12-hour flow battery would make little more net revenue than a solid 2-hour battery; a flow battery's financial viability would require its O&M costs (including loan repayment) to be comparable with those of the 2-hour solid battery. Thus, if storage assets operating over 4-12 hours are deemed a system need, the above analysis suggests that current wholesale price patterns do not give strong incentives for privately owned batteries to provide it, unless their costs per MW are comparable with those of shorter duration batteries. Some kind of local or national flexibility product or ancillary service may be needed to incentivise their deployment.

4.10.3. Comparison of wholesale trades with other activities

Wholesale trades are one out of several different revenue-earning activities batteries could engage in, as described in Chapter 3.

The durations of the real grid connected batteries are not known, but their activity profiles suggest they were all short duration, around 1-2 hours. During the summer case study period, very high revenues were available from provision of frequency response services, far

[56] Limiting battery cycling to 1 cycle per day had no effect at all on 12 hour batteries: Table 22 shows their "best cashflow" scenarios has on average less than 1 cycle / day.

exceeding those from wholesale trades. It is a little surprising that there was any indication of batteries engaging in wholesale trades during that period at all, potentially indicating a barrier or delay to some batteries fulfilling the registration process with the ESO, a necessary prerequisite to response service provision. In contrast to the summer case study period, net revenues from wholesale trades for a 2-hour battery in autumn and winter compare favourably with those from frequency response services, as shown in Table 25.

Table 25 Comparison of overall net revenues from wholesale trades and frequency response services

	Wholesale trades, overall net revenue, ("best cashflow" scenarios) £/day.MW (Table 21 and Table 22)			Highest revenue – frequency response provision (Table 8, Chapter 3[57])	
	1-hour battery	2 hour battery	*4-hour battery*	Most lucrative response service	Revenue, £/day.MW
Summer	*£91*	£157	*£237*	DCL	£848
Autumn	*£175*	£300	*£428*	DCL	£280
Winter	*£209*	£354	*£541*	DRL	£272

The revenues from frequency response service in Table 25 are correct for the best-performing single frequency response service, but during the autumn and especially the winter case study period, underestimate possible earnings an astute provider could make, by offering different response services at different times of day, and on different days, as discussed in Chapter 3. Thus, during the autumn, the owner of a 2-hour battery may make similar overall revenues from frequency response provision and wholesale trades. In winter, the larger gap between overall cashflows from frequency response (single service) and wholesale trades suggests that wholesale trades are probably a little more lucrative. So battery trades would be fairly likely to occur during autumn and winter case studies, though batteries may be expected to jump between provision of different activities e.g. frequency response, on different days, and even in-day.

For any batteries of 1 hour duration, wholesale trades appear unattractive in all seasons, compared to frequency response, though by a smaller margin in winter. For any 4 hour batteries, however, wholesale trades would appear a significantly better option in autumn and winter than frequency response services.

[57] This is the highest revenue from offering a single service, e.g. DCL, for every EFA block and on every day. Higher earnings may be accrued if it is possible to switch between services.

Capacity Market is a useful additional revenue stream for batteries successful at CM auction. This revenue stream requires little difference in battery activity; batteries so engaged would be able to engage in wholesale trades, except during the rare occurrence of the issue of a Capacity Market Notice.

DUoS credits for exports at "red band" times, for batteries connected at HV level, and in exceptional cases at EHV level, would also combine very well with wholesale trades, because the times of day requiring battery exports for DUoS credits tend to have high wholesale prices at the same times, also encouraging exports. For batteries located in southern England or South Wales, TNUoS (Embedded Export) credits, for exports during winter afternoons / early evenings, activity that wholesale price patterns would also encourage, could be a useful additional revenue stream. Similar benefits, for avoidance of TNUoS and DUoS demand charges, could be gained for suitably-located batteries connected "behind the meter" of a large demand site, as described in Chapter 3.

DSO flexibility services may have been an option in some localities, though current prices suggest that incomes would have been modest.

Thus, batteries would have been likely to engage in wholesale trades, especially later in the year, both as a sole activity and also in in combination with other activities. Frequency response services were a more lucrative alternative during the summer case study, and remained an alternative option later in the year, with returns varying between days and at times of day.

Thus, it is not surprising that many of the real GB batteries showed similar behaviour to the simulations at some times, while at other times displayed different behaviours.

4.11. Conclusions

A rational battery could well be expected to engage in wholesale trading activity, either as its sole activity, or in combination with other activities, especially during the autumn and winter case study seasons, when financial returns from trades are comparable with or exceed alternatives.

Despite limitations of the model discussed above, and potential improvements which would benefit it, this battery model is adequate for its intended purpose: to inform network owners, planners, and system operator about potential likely actions of batteries.

While there is no single answer as to what a rational battery would do, even one engaged in wholesale trades, both simulated and real batteries' actions showed a strong diurnal pattern, with one or two imports and exports most days, at consistent times of day.

The results show marked differences in cashflows and battery behaviours between case study seasons. Depending on business model, it may be advantageous to use a battery more actively at times of volatile wholesale prices, when high net revenues from trades are possible, and less actively, or for other activities, at times of low variations in wholesale prices.

Simulated financial returns from a battery engaged in wholesale trades are greatest, per MWh of battery energy capacity, for batteries of the shortest duration, 1 -2 hours, which would incentivise an owner of multiple 1-hour or 2-hour batteries to operate them coincidentally rather than sequentially. If it is a system need to have storage assets of 4 – 12 hour duration, this investigation suggests that wholesale trades alone may not be lucrative, and additional financial support may be needed.

This work paves the way for investigation into the effect a rational battery, engaged in wholesale trades, would have on electricity network congestion.

Chapter 5 investigates potential effects of battery activity on network congestion at Transmission level, using Scotland as a case study. This chapter investigates how simulated battery activity coincided with differing levels of wind generation availability and wind generation curtailment in Scotland, during the case study periods described above.

Chapter 6 investigates potential effects of battery activity on congestion at Distribution level, using six case study locations in southern Scotland. The effect of simulated battery activity on demand-driven import flows, and on wind generator-driven export flows, is examined, during the same case study periods.

5. Chapter 5. Batteries, wind and transmission network flows: a Scottish case study.

Chapter summary

This work investigates the likely impact of battery activity on transmission congestion, using Scotland as a case study; here, transmission network constraints at times of high wind output are common. This work investigates the hypothesis "*a rational battery, engaged in wholesale trades, will not export at times of high wind energy availability in Scotland, nor will it add to network congestion*".

Using the battery model, the three 2022 case study seasons and real price data described in the previous chapter, simulated battery activity timeseries are compared to wind availability timeseries of Scottish wind generators which participate in the Balancing Mechanism. Aggregate durations of battery imports and exports, at different conditions of wind, are enumerated. This work found against the hypothesis: battery imports and also exports would be expected at all conditions of wind, including high wind conditions during which curtailment of wind generators is common or continuous. This result holds for all case study seasons, for batteries of duration between 1 and 12 hours, operating under a "best cashflow" scenario, and also for 2-hour duration batteries operating under two "lower cycling" scenarios.

Under all conditions of wind, diurnal variations in price occurred most days, providing opportunities for a storage asset to trade and accrue revenue. Battery exports at times of high wind will add to network congestion. Network planners and the ESO must allow for the possibility that batteries or other storage assets, and indeed other generators, if located in Scotland and engaged in wholesale trades, may add to network congestion.

This work highlights the importance of suitable price signals if storage and other network users are to aid rather than hinder network operation.

5.1. Introduction

The context for this work is in Scotland, the northernmost home nation of the island of Great Britain, and whose electricity system forms the northern part of the GB-wide synchronous electrical power system and single electricity trading area.

Scotland's abundant wind resource and its areas of sparse population, together with UK and Scottish Governments' policy measures encouraging renewables, have resulted in over 10 GW of wind deployment Table 26 [214]–[216]. Scotland is home to 8.3% of the population of Great Britain [217], with current peak gross electrical demand of 4 GW, expected to rise to 6 GW by 2030 [218]. Thus at times of high wind, wind generation, together with other inflexible generation (from a nuclear power station and various other distribution-connected generators) significantly exceeds electricity consumption in Scotland.

Table 26 Wind generation capacity, MW: Scotland, May 2023 [214]–[216], [219], and GB, end 2022 [220]

	Distribution-connected	**Transmission-connected**	**Total**
Scotland onshore wind	*3,855*	*5,522*	*9,377*
Scotland offshore wind	*50*	*1,583*	*1,633*
Scotland total wind	**3,905**	**7,105**	**11,010**
GB onshore wind	*7,493*	*5,911*	*13,404*
GB offshore wind	*598*	*13,329*	*13,927*
GB total wind	**8,091**	**19,240**	**27,331**

While significant investment electricity networks has been conducted alongside this growth in new generation capacity, the rate of both Transmission and Distribution network capacity growth has lagged significantly behind, in part due to long design, planning and commissioning timescales. At Transmission level, Scotland usually exports electricity to other parts of GB, with maximum flows at times of high wind output [218], [221]. Curtailment (i.e. the active reduction in power output below unconstrained levels) of some Scottish windfarms is often necessary, because of insufficient transmission capacity, or to enable other actions by National Grid Electricity System Operator (NGESO), and is discussed below. In particular, the ESO-defined "B6" transmission boundary (which delimits the Scottish transmission zones from the rest of the GB transmission network) is a significant bottleneck to the export of wind power to larger areas of demand further south. Chapter 5 Annex 1has maps showing this boundary.

As discussed in Chapter 2, storage has the potential to alleviate network constraints and ultimately reduce overall cost of running the electricity system [59]. Furthermore, as discussed previously in Chapter 3, there is currently much interest in deployment of grid-scale batteries at both Distribution and Transmission scales [214]–[216], [222], [223].

It could reasonably be expected that at times of high output from renewable generators, including wind generators, which have low or zero short-run marginal cost, the wholesale price will be lower than at times when system demand is met largely from fuel-fired generators. Thus, one could expect that at times of high wind, the battery will be incentivised to import electricity, and conversely, at times of low wind, the battery would be incentivised to export. In such a situation a battery or other storage device would naturally act to reduce both import and export network flows, and so would relieve network congestion. However, the price of electricity is affected by a number of factors, and the above assumption might not be the case, as is elaborated later in the Discussion section.

This work examines the likely behaviour of a battery participating in wholesale market trading, to investigate the hypothesis:

> "*a rational battery, engaged in wholesale trades, will not export at times of high wind energy availability in Scotland, nor will it add to network congestion*".

5.2. Method

5.2.1. Wind availability: preparation of timeseries

Balancing Mechanism data were used to estimate overall wind energy availability.

Balancing Mechanism (BM) data list Final Physical Notifications (FPNs), Bid Accepted Volumes (BAVs) and Offer Accepted Volumes (OAVs) for each Settlement Period (SP), for all participants in the Balancing Mechanism, termed Balancing Mechanism Units (BMUs) [147], [148]. These datasets cover all transmission-connected generators, and some of the distribution-connected generators.

These Wind FPNs were used as a metric of wind *availability*, i.e. estimated output of wind generators before any curtailment instructions.

Wind availability timeseries during 2022 were prepared using the sum of FPNs, in MW, of all onshore and offshore Scottish BMU windfarms.

To fit with outputs of battery model, which use hourly-resolution price data, as described in Chapter 4, the wind data were smoothed from half-hourly to hourly resolution.

Wind capacity factor

The level of wind availability (total wind FPN) at any time t is described in MW and also by its *capacity factor*, i.e. relative to the maximum wind availability. This metric is necessary in later calculations to categorise wind availability together with battery activity.

The metric of maximum wind availability used here is the sum of *non-coincident maximum availabilities* of every Scottish BMU windfarm, during 2022.

$$MaxWindAvailability_{Scotland,2022} = \sum \max\,(hourly\ FPN)_{indivScottishwfms,2022} \tag{5.1}$$

$$wind\ capacity\ factor_t = \frac{\sum HourlyFPNs_{Scottishwfms,t}}{MaxWindAvailability_{Scotland,2022}} \tag{5.2}$$

Thus, timeseries of total Scottish wind availablity (FPN) in MW and also as a capacity factor were obtained for the whole of 2022, and for each case study season.

The approach is summarised in Figure 43.

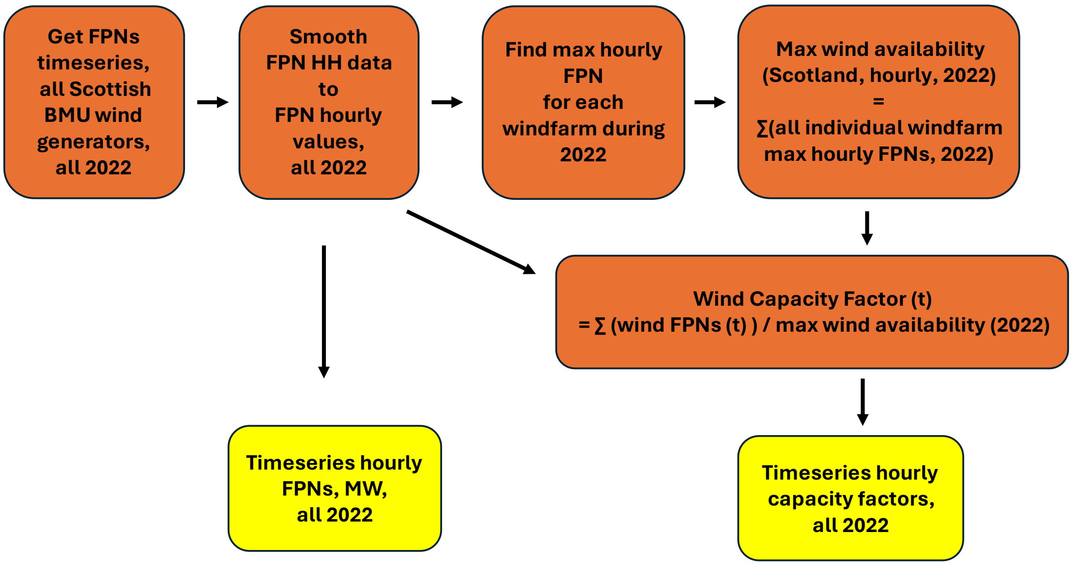


Figure 43 Schematic of approach to obtain timeseries wind availability timeseries in MW and as a capacity factor

For ease of description, the wind availability values were split into quintiles, as described in Table 27.

Table 27 Definition of wind availability quintiles

Wind availability capacity factor	Quintile
0 - < 20%	Quintile 1 (Q1)
20% - < 40%	Quintile 2 (Q2)
40% - < 60%	Quintile 3 (Q3)
60% - < 80%	Quintile 4 (Q4)
80% - 100%	Quintile 5 (Q5)

5.2.2. Wind availability and windfarm curtailment during each case study season, and all of 2022.

This subsection views the total durations of both *wind availabilities* and *windfarm curtailments* which occurred during each quintile of wind availability. This was performed for the whole of 2022, and for each case study season.

5.2.2.1. Wind availability durations

The number of hours during the year during which Scottish wind energy availability (total hourly FPNs) fell within each wind availability quintile was enumerated. The procedure was repeated for each case study season.

5.2.2.2. Windfarm curtailment durations

Total curtailment of Scottish windfarms was enumerated using BM datasets BAVs – for generators required to reduce output (or demand users to increase consumption), and OAVs – for generators instructed to increase output (or demand users to reduce consumption), as mentioned in Section 5.2.1.

As with the FPN datasets, the BAV and OAV timeseries, downloaded as half-hourly resolution, were smoothed to hourly timeseries datasets before any further calculations.

At any timestep t, the overall volume of wind energy curtailed in Scotland is described by the "Net BAV", as given by the following equation:

$$Net\ BAV_{Hourly,AllScottishWindGenerators,t} = BAV_{Hourly,AllScottishWindGenerators,t} + OAV_{Hourly,AllScottishWindGenerators,t} \tag{5.3}$$

(The BAV and OAV values are summed, not subtracted, because BAV values are negative, and OAV values are positive, as are FPN values for all units providing net generation.)

The timeseries of Net BAVs was viewed alongside the timeseries of wind availability and wind capacity factor, as described in the subsection above, for the whole of 2022, and for each case study season.

The total number of hours during which one or more windfarm in Scotland received an instruction to reduce output (i.e. $NetBAV_t > 0$), was enumerated for each wind availability quintile, during 2022.

The procedure was repeated for each case study season.

5.2.3. Battery activity

5.2.3.1. Base case battery, "best cashflow" scenarios

For each case study period, battery simulations were performed, for the "default" battery parameters: 2 hour duration, 85% round-trip efficeincy, using the trading parameters of the "best cashflow" scenarios described in Chapter 4.

The timeseries of battery actions was obtained for each case study period.

These timeseries were viewed together with the timeseries of wind FPNs. The battery import and export actions were categorised according to the wind energy quintile during which they happened. The total number of hours of battery imports and exports were enumerated for each wind energy quintile, for each case study season.

As the durations of the quintiles themselves varied between quintiles, and between seasons, the *proportional duration* of battery activity, as a percentage of the number of hours of the respective wind availability conditions, was also enumerated.

$$proportional\ battery\ activity\ duration_{quintile,season}$$

$$= \frac{battery\ activity\ duration(hrs)_{quintile,season}}{duratation\ of\ wind\ availability(hrs)_{quintile,season}} \tag{5.4}$$

For example, in the winter case study season:

No. of hours of wind quintile 5 conditions	=	25 hours
No. of hours of battery imports during wind quintile 5	=	4.7 hours
No. of hours of battery exports during wind quintile 5	=	2.0 hours

Thus,

$$proportional\ duration\ of\ battery\ imports_{Q5,winter} = \frac{4.7hrs}{25\ hrs} = 19\%$$

$$proportional\ duration\ of\ battery\ exports_{Q5,winter} = \frac{2hrs}{25\ hrs} = 8\%$$

5.2.3.2. Base case battery, lower-cycling scenarios

The procedure described above was repeated for the 2-hr battery, but with different trading scenarios which involved lower battery cycling, as identified in Chapter 4, Section 4.7.4 , and stated in Table 21.

5.2.3.3. Other batteries

The procedure described above was repeated for batteries of different duration, in each case, selecting the single “best cashflow” scenario for the battery type and season, as previously identified in Chapter 4, in Section 4.8.3. The battery parameters selected are previously shown in Table 22, in Chapter 4.

5.2.4. Potential correlations of wholesale price with wind and other factors

It was desired to understand the potential influence of Scottish wind and other factors on wholesale electricity prices, the latter driving battery trading activity.

Timeseries plots of Scottish & GB wind availability (FPNs) vs wholesale price have been prepared (Figure 44, and Chapter 5 Annex 2 (Annex 2.1, 2.2. & 2.3).

Later in this chapter, scatterplots were prepared to examine any possible relation between wholesale price, wind and some other factors. Table 28 summarises the metrics considered.

Table 28 Metrics against which wholesale price data was examined

Variable	Metric used	Type of plot
Wind availability (Scottish and GB)	FPNs	Timeseries & scatterplots
Estimated wind output (Scottish & GB)	FPNs + BAVs + OAVs	scatterplots
Wind curtailment (Scottish & GB)	BAVs + OAVs	Scatterplots
Time of day	SP no.	Scatterplots
Electricity demand	Total transmission demand (TSD)	Scatterplots

Scottish and GB wind metrics were all sourced from Elexon as described above. Transmission system demand data were sourced from NESO [17]. All metrics were convereted from half-hourly to hourly resolution data to fit with the hourly resolution pricing data.

5.3. Results

5.3.1. Wind availablility

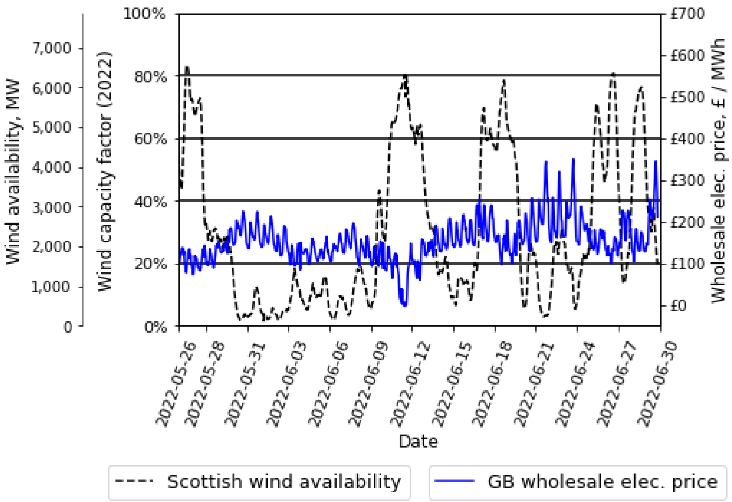
The non-coincident maximum wind availability (FPN) from all Scottish windfarms during 2022 was found to be 7,865 MW, using FPN values which had been smoothed to hourly resolution. This value is used as the denominator for calulcation of wind availablity capacity factor (CF), and for enumeration of wind availablity quintiles, which are displayed in Table 29.

The highest hourly *coincident* overall wind availability (not used in calculations) was 6,972 MW.

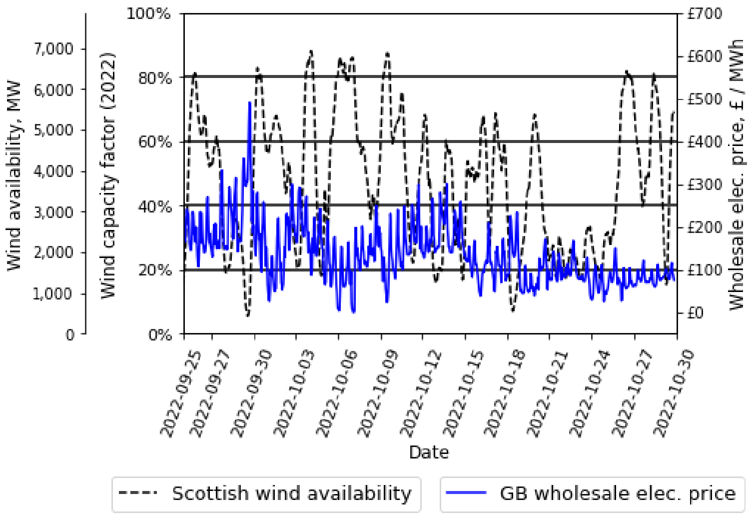
Table 29 Range of total Scottish wind FPNs in each wind energy availability quintile

Wind availability capacity factor (CF)	**Quintile**	**Total wind availablity (total hourly FPNs), MW**	
		Min value	Max value
0 - < 20%	Quintile 1 (Q1)	0	< 1,573
20% - < 40%	Quintile 2 (Q2)	1,573	< 3,146
40% - < 60%	Quintile 3 (Q3)	3,146	< 4,720
60% - < 80%	Quintile 4 (Q4)	4,720	< 6,293
80% - 100%	Quintile 5 (Q5)	6,293	< = 7,865

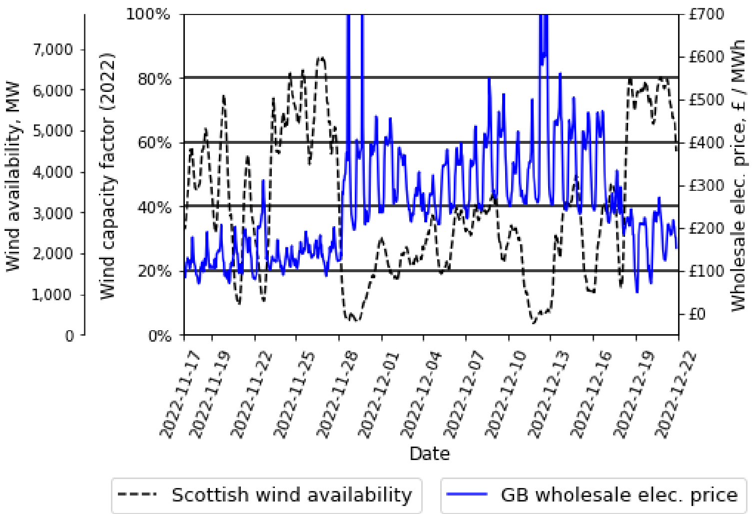
Figure 44 shows the timeseries for Scottish hourly wind availablity (total FPNs) in MW and as capacity factor, as the black dashed line, for the three case study periods. The wholeasale price data timeseries are also displayed (blue line), because these drive the battery trading behaviour, which is shown later. (This chart restricts the maximum price axis to £700 / MWh for better viewing of the patterns of price; in the winter case study, the electricity price exceeded value on four occasions. Plots showing full-scale price axis are shown in Chapter 5 Annex 2. For reference, Chapter 5 Annex 2 also shows timeseries plots of Scottish and GB wind availability for the three case study periods, together with price data.)



(a) Summer case study



(b) Autumn case study



(c) Winter case study

Figure 44 Scottish wind availability and capacity factor (hourly) and wholesale trading price, 2022, Summer, Autumn and Winter case study periods (restricted scale price axis)

5.3.2. Wind energy availability and wind curtailment

5.3.2.1. Wind energy availability , all 2022

As described in subsections 5.2.2.1, the number of hours during which the wind availability fell into each wind availability quintile during 2022 was enumerated. These durations are shown by the solid black bars in Figure 45, and also in tabular form in Chapter 5 Annex 3 Table 93. The wind energy quintiles, which form the x-axis in Figure 45, are the same values as those shown on the left-hand y-axes in the charts of Figure 44 above; the corresponding values of wind availability in MW are tabulated above in Table 29.

These black bars of Figure 45 show that Scotland has significant wind resource: there are significant durations at which all levels of wind availability occur (other than the windiest quintile Q5). Though "quintile 1", the lowest wind quintile, occurs for more hours than any other single quintile, Q1 only accounts for about one third of the year. The aggregate number of hours of wind quintiles 2 to 4 collectively account for approaching 2/3 of the year.

It is not surprising that the number of hours of wind levels in quintile 5 is relatively small, because the highest Scottish *coincident* wind availability was just under 7,000 MW, corresponding to a capacity factor of 90.2%.

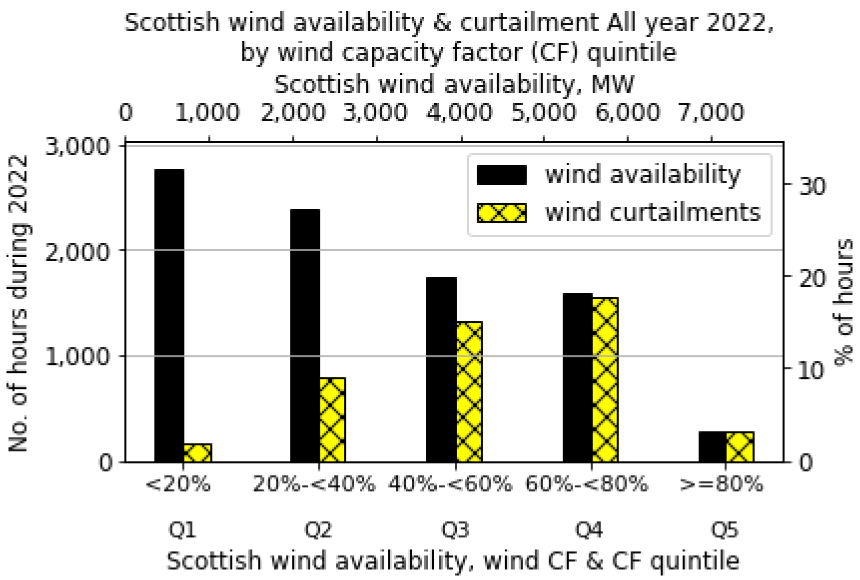


Figure 45 Durations of Scottish hourly wind energy availability (total hourly FPNs), and Scottish hourly wind generation curtailment (total hourly net BAVs) vs wind energy availability Capacity Factor (CF) quintile. All 2022.

5.3.2.2. *Wind energy curtailment, all 2022*

The number of hours during which wind energy curtailment, of one or more Scottish windfarms occurred, and the number of these hours which fell within each wind availability quintile, was enumerated as described in Section 5.2.2.2. These hours of curtailment are shown in the yellow hatched bars in Figure 45, and also in tabular form in Table 94 in Chapter 5 Annex 3.

These bars show that wind energy curtailment occurred at all quintiles of wind energy availability, but correlates very strongly with wind energy availability. The number of hours of curtailment during wind energy quintile 1, corresponding to low wind, was small. From wind energy quintile 1 to 4, the number of hours of wind curtailment increased substantially with each wind quintile. Curtailment occurs for the majority of the duration of wind quintile 3 conditions, for all but a few hours of wind quintile 4 conditions, and for all hours of wind quintile 5 conditions.

5.3.2.3. *Wind energy and wind energy curtailment, case study seasons*

Figure 46 is a similar chart to Figure 45, but for the three case study seasons.

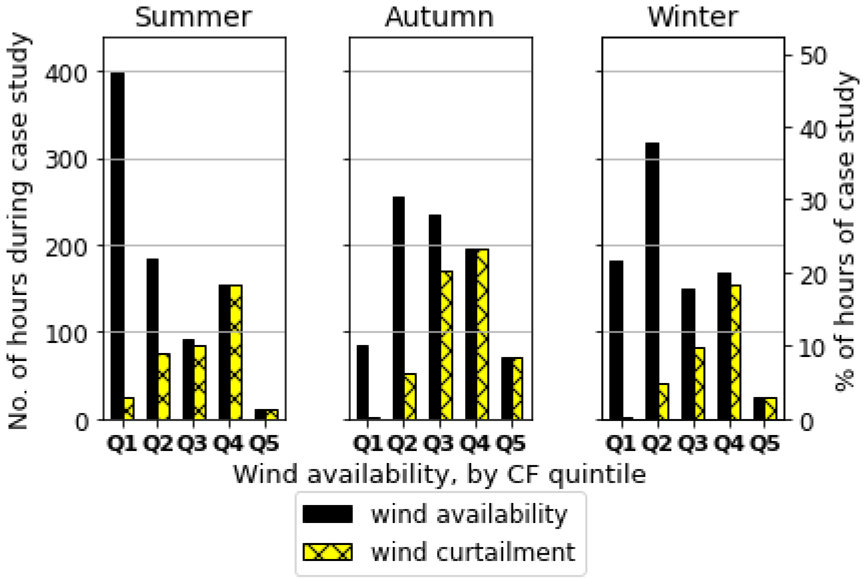


Figure 46 Durations of Scottish hourly wind energy availability (total hourly FPNs), and Scottish hourly wind generation curtailment (total hourly net BAVs) vs wind energy availability quintile. Summer, autumn and winter case study seasons.

Looking at the black bars of Figure 46, showing durations of wind energy availability vs wind energy availability quintile, it is clear that there were significant differences in the patterns of wind energy availability from the Scottish windfarm fleet between the three seasons, presumably because of weather differences. The summer case study season has the longest aggregate duration of low-wind conditions falling within "Quintile 1", as can also be seen in Figure 44 (a) and Table 93 in Chapter 5 Annex 3. In contrast, the autumn case study season has the longest durations at higher wind energy availability quintiles 3-5, as is also evident in Figure 44 (b), and in Table 93 in Chapter 5 Annex 3.

Regarding wind curtailment, the yellow hatched bars in Figure 46 show an effect of wind quintile, and also an effect of season.

Regarding effect of wind quintile, these charts show that aggregate durations of curtailment rise with wind energy quintile number over quintiles 1-4 during each case study season (data are tabulated in Table 94 in Chapter 5 Annex 3). The summer and autumn charts in this figure show the same number of hours of wind availability, and also of wind curtailment, for Q4 and Q5. This shows that the ESO instructed one or more windfarms to curtail, on every hour of wind FPNs at these high levels. However, at lower levels of wind in Q2 and Q3, the ESO instructed one or more windfarms to curtail on some but not all occasions, hence the yellow bar (no. of hours of curtailment) is much lower than the black bar (no of hours of wind at this level). At low wind conditions Q1, occasions of curtailment at low wind Q1 are infrequent.

These charts also show a seasonal effect on wind curtailment. In summer, there are significant durations of curtailment at lower wind energy quintiles, with almost all (91%) hours of wind energy quintile 3 having curtailment. In contrast, in winter, there is proportionately less curtailment at every wind energy quintile 1-4, with only just over half of the hours of wind quintile 3 having curtailment. Presumably higher demands in winter reduce generation-driven network congestion; whereas during times of lower demands in summer, ESO actions to manage the congestion are needed more often.

These data describe the background conditions in which battery activity is investigated.

5.3.3. Battery activity

5.3.3.1. Base case battery (2hrs, 85% round trip efficiency), "best cashflow" scenario

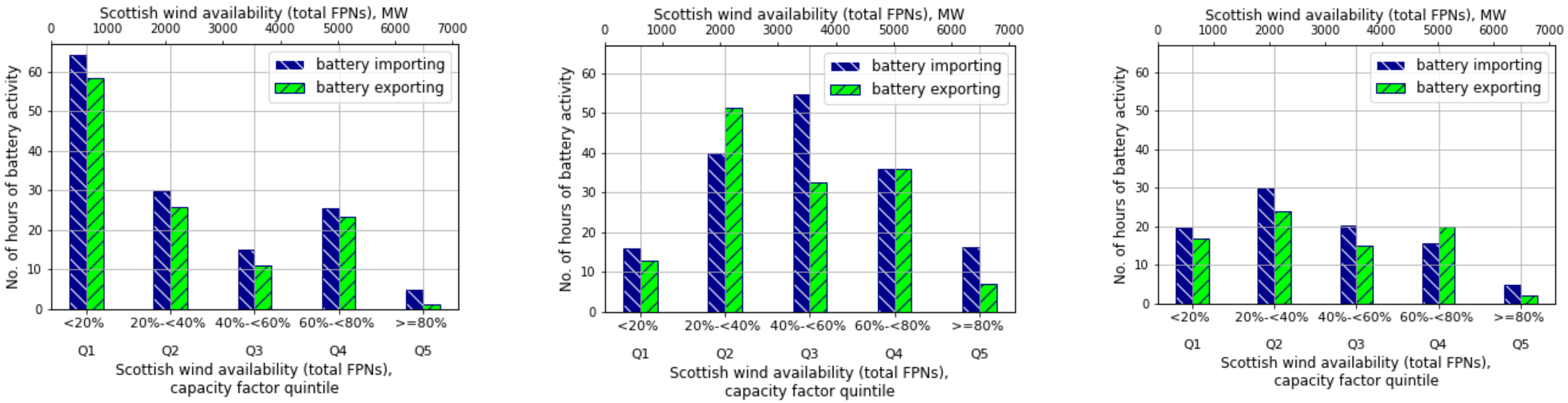
The aggregate durations of battery imports and exports, during each quintile of wind energy availability, are shown in Figure 47, for each case study season. The numbers of hours are tabulated in Table 95 in Chapter 5 Annex 4.

In all three seasons, battery imports and exports occurred at all wind energy quintiles. The durations of imports and exports varied significantly between quintiles and seasons, as did the durations of conditions of the different wind quintiles, as shown in Figure 46.

The *proportional* durations of battery imports and exports (percentage of the aggregate duration of conditions of the respective wind quintile and cases study season, during which battery import or export occurred, as defined in Section 5.2.3.1) for the three case study seasons are displayed in Figure 48.

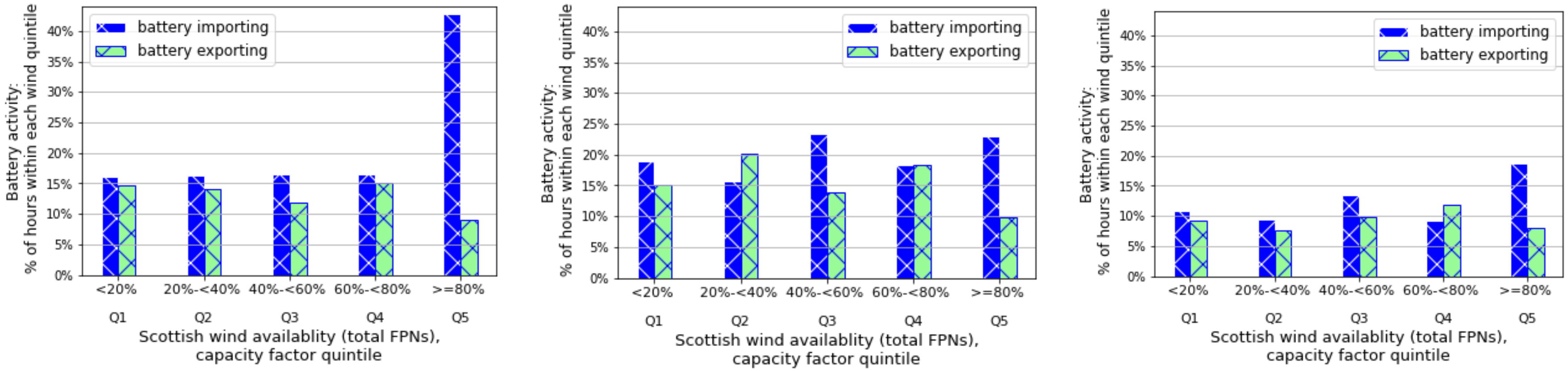
In contrast to the absolute aggregate duration of battery imports and exports, which varied considerably between seasons and wind energy quintiles, the *proportional* durations of battery imports and exports, in many cases, were similar, between wind quintiles and also between seasons. For wind energy quintiles 1 to 4, all proportional imports and exports were between 12% and 24% of the duration of the respective wind quintile condition, during the summer and autumn. During the winter season, when the battery was less active, proportional imports and export durations during wind quintiles 1-4 were between 8% and 14%. Across the three seasons, the very windiest quintile 5 had very short durations: the proportional durations of battery imports were longer than during the other quintiles, ranging from 19% to 43% of this respective quintile duration; battery export proportional durations ranged from 8% to 10% of the respective quintile duration.

Import durations were a little longer than export durations, because, as described in Chapter 4, Section 4.4.2 the model defines battery's import and export rates (MW) as being equal, and so additional import time is needed to cover the round-trip losses.



(a) Summer (b) Autumn (c) Winter

Figure 47 Aggregate durations of battery imports and exports during each wind energy availability quintile. Summer, Autumn and Winter case studies. Base case battery (2 hrs, 85% round trip), "best cashflow" scenario for each season



(a) Summer (b) Autumn (c) Winter

Figure 48 Proportional durations of battery imports and exports, i.e. duration of battery activity as a percentage of each respective wind quintile duration. Summer, Autumn and Winter case studies. Base case battery (2 hrs, 85% round trip), "best cashflow" scenario for each season

5.3.3.2. Base case battery, lower cycling scenarios

Battery activity vs wind energy quintile is tabulated and displayed graphically in Chapter 5 Annex 4: Annex 4.2, for two alternative lower cycling scenarios ("Second choice – lower cycling" in Annex 4.2.1, and "Third choice – lowest cycling" in Annex 4.2.2). In all cases, there was battery activity, both imports and exports, at all wind energy quintiles.

5.3.3.3. Other batteries: 1-hour, 4-hour, 12-hour and 12-hour 70% round trip efficiency

For the batteries of shorter and longer durations, battery activity vs wind energy quintile is tabulated and displayed graphically in Chapter 5 Annex 4: Annex 4.3. Again, in all cases, there was battery activity, both imports and exports, at all wind energy quintiles.

5.3.3.4. Overall patterns

Chapter 5 Annex 5 shows the *proportional* battery activity duration for each wind energy quintile, grouped by case study season. A few examples are shown below:

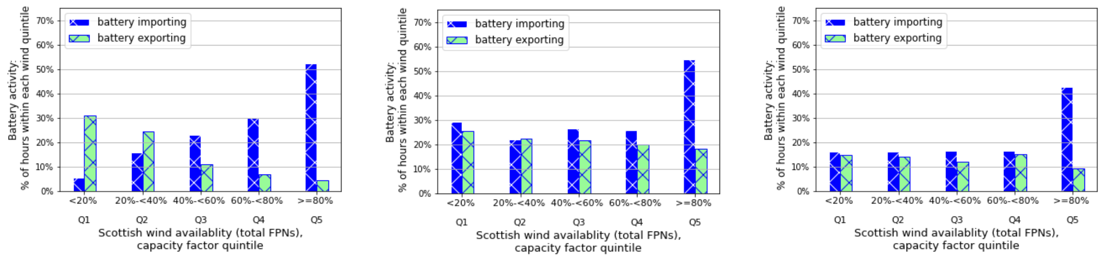
Proportional duration of import increases with wind energy quintile, and proportional duration of export decreases.

This result could feasibly be expected, given that wholesale price would be expected to correlate inversely with the amount of low-short-run marginal price generation.

The bar charts of Figure 49 below display battery activity duration in each wind energy quintile, as a proportion of the aggregate duration of wind conditions of that quintile. The blue bars show the proportional duration of aggregate battery *imports*, and the light green bars the proportional durations of aggregate *exports*.

These charts show that battery imports – blue bars - are generally higher at higher wind quintiles than lower wind quintiles. The opposite is the case for the pale green bars showing battery exports.

The first chart, the 12-hour 70% efficiency, autumn, shows a clear and strong relation between import and export duration with wind quintile. In the other two charts the aggregate import duration is longer only at the windiest quintile, Q5, and the relation between aggregate export duration with wind quintile is less distinct than that of aggregate import duration with wind quintile.



(a) Autumn, 12 hr battery, 70% round-trip eff

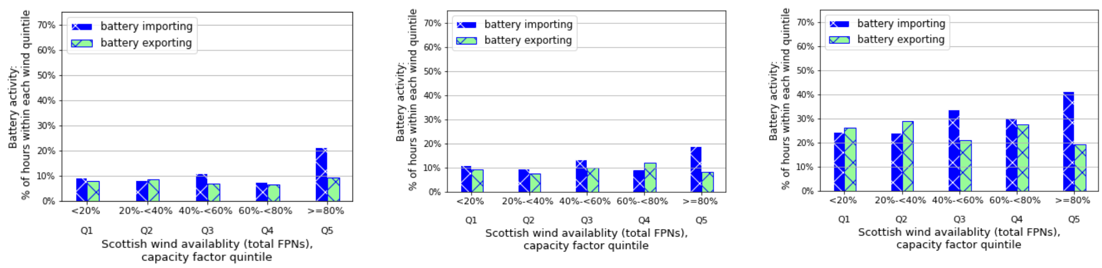
(b)Summer, 4 hr battery

(c) Summer, 2 hr battery (best cashflow)

Figure 49 Proportional duration of battery imports and exports. Examples where battery imports increase and exports decrease with increasing wind.

Proportional duration of import increases with wind energy quintile, but there is no clear pattern of proportional duration of export with wind energy quintile.

Several of the charts displayed this generic pattern, especially during the summer case study. An increase in proportional duration of battery *import* was found with increasing wind quintile. However, by inspection, there appears to be little link between wind quintile and battery *export* behaviour.



(a) Summer, 1 hr battery

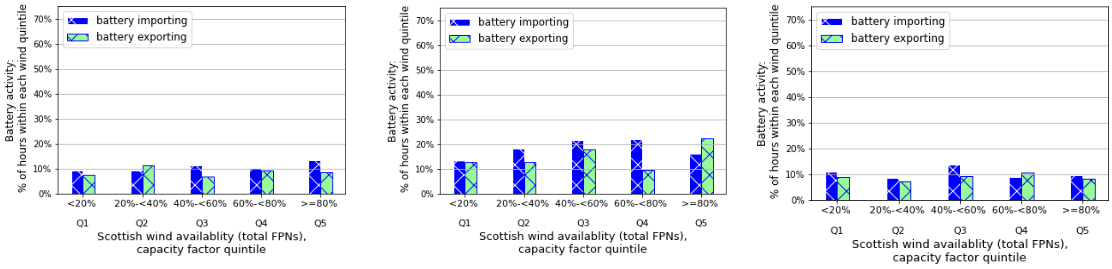
(b) Winter, 2 hr battery (base case)

(c) Autumn, 4 hr battery

Figure 50 Proportional duration of battery imports and exports. Examples where battery imports increase with increasing wind, but the correlation between wind and battery exports is unclear.

No clear pattern with either battery imports or exports with wind energy quintile

Several of the scenarios, especially those for the winter case study season, had little overall pattern between wind energy quintile and either battery imports or exports.



(a) Autumn, 1 hr battery

(b) Winter, 12 hr 70% round-trip battery

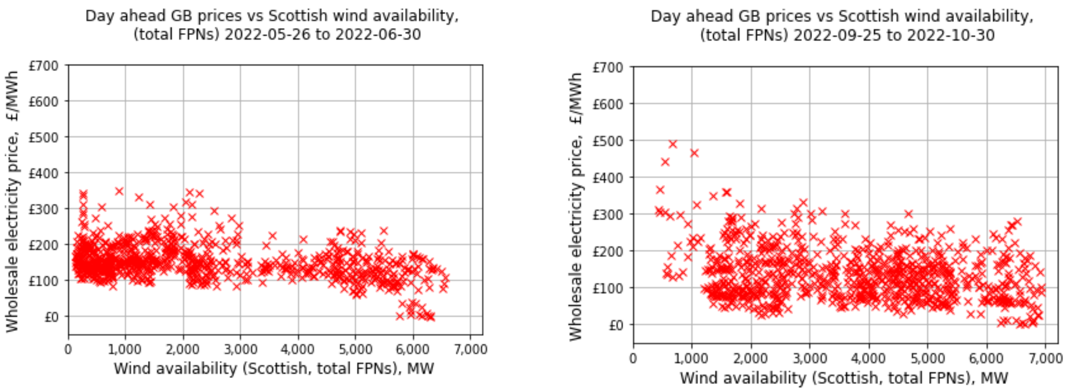
(c) Winter, 2 hr battery, lower cycling scenario

Figure 51 Proportional duration of battery imports and exports. Examples where the relation between wind and battery activity, both imports and exports, is unclear.

5.3.4. Potential correlations of wind and other metrics with wholesale electricity price

5.3.4.1. Correlation of wholesale price and wind metrics

A negative correlation was observed between Scottish wind availability and wholesale price: the highest prices occurred at times of low wind, and the lowest at high wind. However, the relation was very weak, as is shown in Figure 52 for the summer and autumn case study periods



(a) Summer

(b) Autumn

Figure 52 Scatterplot of wholesale electricity price vs Scottish wind availability, summer and autumn case studies

The winter case study period had three distinct regions in its timeseries price and wind availability values, as described in Figure 53.

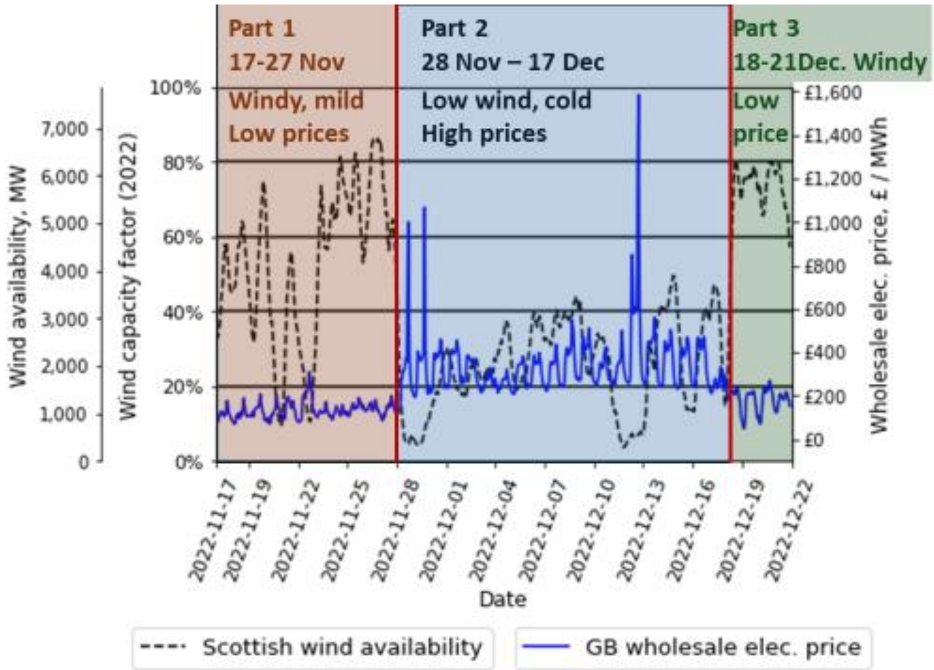
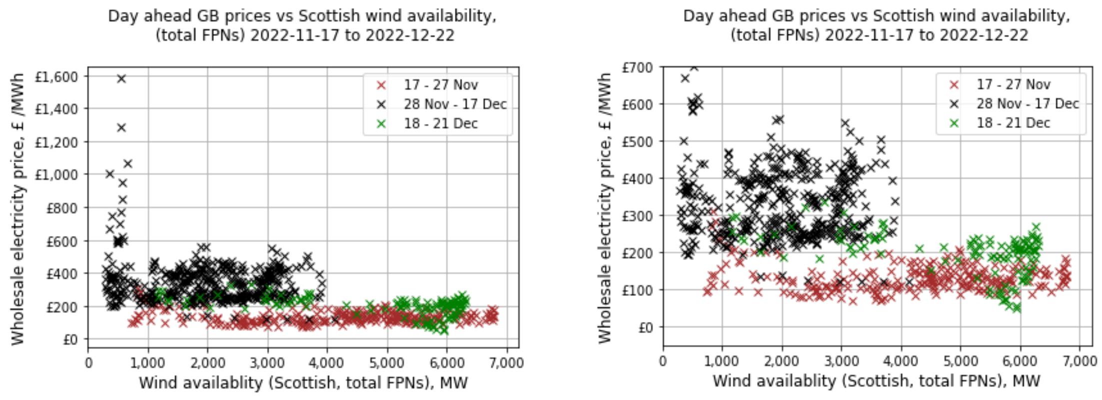


Figure 53 Winter case study season. Delineation of the time period into 3 parts according to price and wind.

The scatterplot for winter, Figure 54, distinguishes these three parts by colour. This plot shows that during the winter case study period, extremely high prices occurred on a few occasions: these prices all occurred at times of low wind availability. Among the black coloured markers, for 28 Nov to 17 Dec inclusive, aside from a handful of extreme price events, however, the relation between wholesale price and wind is unclear. Among the brown coloured markers there is a similar picture, of higher prices at low wind, but other than that little relation between wind and price. Among the green markers covering the last 4 days, their distribution lies within two areas of the plot: a few green markers within the “low to moderate wind” (up to 4,000 MW), and “moderate” prices (£190-£350 / MWh) area of the plot; and more green markers in the plot area of “high” wind (over 4,000 MW) and low to moderate prices (around



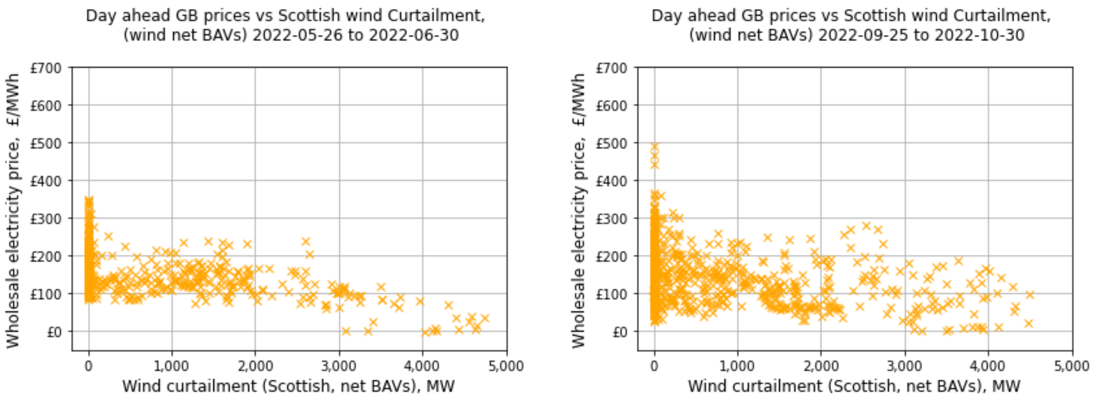
(a) Winter – full price scale (b) Winter – cropped price scale

Figure 54 Scatterplot of wholesale electricity price vs Scottish wind availability, winter case studies

£40-£290 / MWh).

Very weakly negative correlations were also observed, by inspection, for wholesale price against estimated Scottish wind *output* (i.e. FPNs net of balancing actions), as shown in Chapter 5 Annex 6: Annex 6.2, and also for price against GB wind availability (Annex 6.3), and price against GB estimated wind output (Annex 6.4).

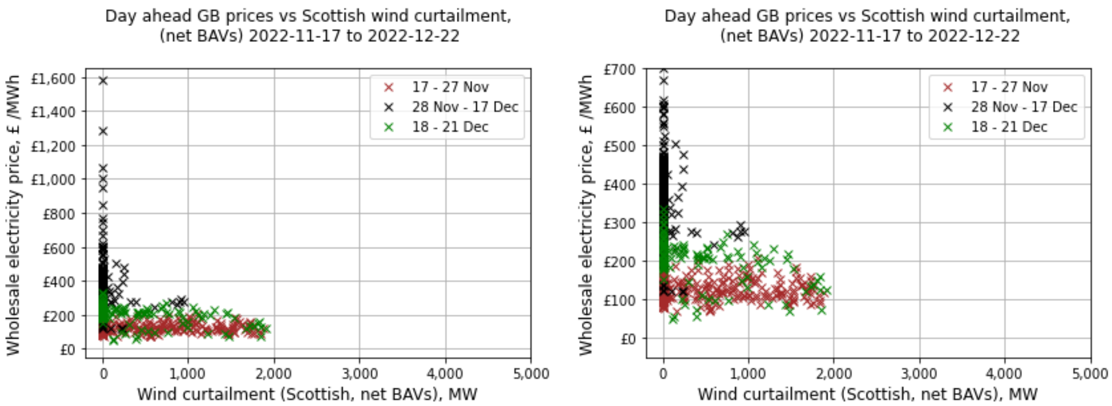
Slightly stronger negative correlations were observed, by inspection, between price and volume of Scottish wind curtailment, with the highest prices occurring when there was no or little curtailment, as shown in Figure 55, and Chapter 5 Annex 6: Annex 6.5, though there is considerable range of wholesale prices occurring at most levels of curtailment.



(a) Summer (b) Autumn

Figure 55 Scatterplot of wholesale electricity price vs Scottish wind curtailment (total net BAVs), summer and autumn case studies

In the winter case study, shown in Figure 56, the extreme high prices only occurred at times of zero curtailment; however at other times the relation between price and curtailment was unclear.

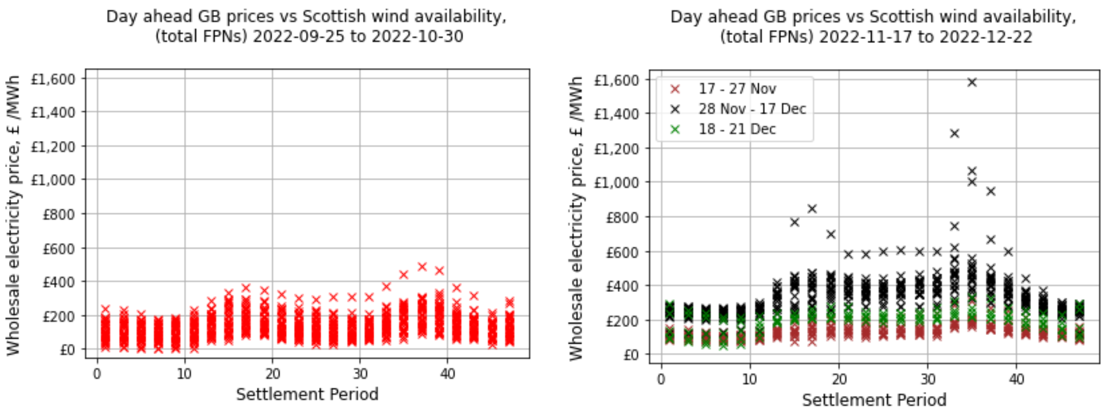


Winter – full price scale Winter – cropped price scale

Figure 56 Scatterplot of wholesale electricity price vs Scottish wind curtailment (total net BAVs), winter case study

GB curtailment is plotted against price in Chapter 5 Annex 6: Annex 6.6. It differs very little from Scottish curtailment.

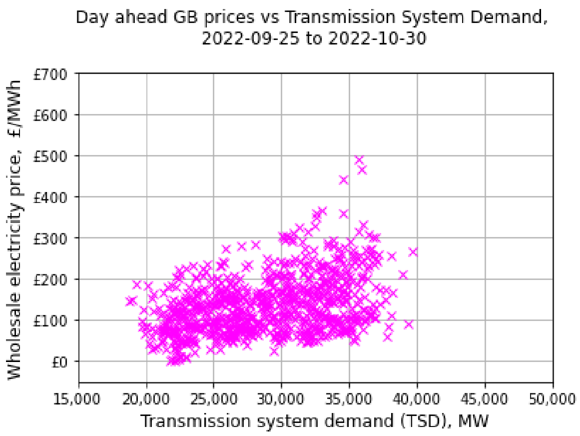
There is a more distinct relation between price and time of day, for example as shown in Figure 57 below and in Chapter 5 Annex 6: Annex 6.7. There is considerable range of prices for each settlement period, but a "two peak a day" pattern is evident on most days of in the summer and autumn case studies, with price maxima in the early evening and also in the morning. The winter case study shows a "one or two peak a day" pattern.



(a) Autumn (b) Winter

Figure 57 Scatterplot of wholesale electricity price vs time of day (Settlement Period, 1-48), (a) Autumn and (b) Winter case studies

Finally, a positive correlation is observed, by inspection, between price and Transmission System Demand, using the "TSD" data from NESO [17] , though with considerable scatter, as shown in in Figure 58 and Chapter 5 Annex 6: Annex 6.8.



Autumn

Figure 58 Scatterplot of wholesale electricity price vs Transmission System Demand. Autumn case study

5.4. Discussion

5.4.1. Wind and curtailment

Conditions of high wind availability are prevalent in Scotland. Conditions of wind quintiles 3-5 occurred during 3,608 hours of 2022, 41% of the year. During the same wind energy quintiles, curtailment of one or more wind generator occurred during 3,154 hours, or 87% of the aggregate duration of these wind conditions.

Out of all of the 4,091 hours of 2022 during which curtailment occurred, 47% of the year, the 3,154 hours of curtailment which occurred during wind quintiles 3-5 accounted for over three quarters (77%) of all hours of curtailment.

However, some curtailment occurred during all levels of wind, with 154 hours during the year occurring during the lowest-wind quintile, Q1. Curtailment during Q1 was more common during the summer than the other case study seasons.

It is surmised that the main reason for the highest proportional curtailment for each quintile (1 to 4) occurring in summer, and the lowest in winter, is that overall electricity system demands are generally higher in winter and lower in summer. Furthermore, especially in summer, small scale rooftop or other behind-the-meter solar generation may add to Scotland's total inflexible generation at times, and further increase the need for curtailment when sunny and windy conditions occur together. Seasonal ratings of conductors may also increase transmission capacity during winter compared to other seasons.

5.4.2. Wind, battery behaviour, and price

It is not entirely surprising that batteries would continue to trade during windy weather. The timeseries plots Figure 44 shows clearly that diurnal variations in wholesale price occurred on most days, at all conditions of wind. The scatterplot of wholesale price vs time of day Figure 57 (and Annex 6.7 in Chapter 5 Annex 6) shows a similar overall picture. Such short-term price variations provide opportunities for batteries to trade and accrue revenue, and it would be entirely rational for a battery or other storage asset, if engaged in wholesale trading activity, to do so. As reported in Chapter 4, Section 4.7.3, a "one-cycle-a-day" battery behaviour was simulated for many days in the winter case study, and "two-cycles-a-day" battery actions on many days in the summer and autumn case studies, with highest prices incentivising exports occurring in early evenings, and also, in many cases, in the morning. Furthermore, Chapter 4

Section 4.9 describes examples of real GB grid-connected battery BMUs showing both types of behaviour during these case study periods.

The scatterplots shown in Section 5.3.4 show that though correlations between wholesale price and wind (Scottish and GB, availability and estimated output) exist, they are very weak. The overall correlation with system demand is a little stronger. Clearly price is an output of a combination of these and other factors, including the price of gas, which was high and volatile during late 2022 [224].

A similar situation is described in Chapter 2 Section 2.3 by [92], [94], [95], set in Canada and the USA: a "self-interested" battery, engaged in wholesale trades, would behave differently to one dedicated to minimising network constraints or maximising penetration of renewable generation remote from demand centres. Denholm and Sioshansi also observe in [94] that wind penetration was not at a level to have much influence on electricity prices, thus "price-driven" storage behaviour would differ from "wind-driven" actions.

Wind generation across GB, either alone or in combination with any solar, did not manage to entirely displace gas generation as the price setter, hence its limited impact on price. Reasons include transmission constraints, in particular across the B6 boundary, limiting Scottish wind penetration into the GB system. Presumably in 2022, even if such renewables outputs were available and not limited by transmission capacity, the ESO would have been likely to curtail to allow headroom for synchronous generation to aid system operability. The ESO reported having engaged in such activity during periods of low system demand and high renewables outputs during Covid lockdown in early summer 2020 [225]. In 2019 the ESO committed to "zero carbon system operation" by 2025, after which year the ESO would no longer "constrain on" fossil fuel fired generation at the expense of low-carbon generation to manage system operation, a change which the ESO director described as *"a fundamental change to how our system was designed to operate*" [18], [226].

The conditions in which this study was conducted are changing. Significant increase in transmission capacity, including across the B6 boundary, is likely to become realised over the coming decade, which may relieve network constraints, though deployment of further wind capacity is also expected [218], potentially at volumes which will continue to outpace transmission capacity increases. The ESO's target date for "zero-carbon operation" is approaching. The UK Government set a target to fully decarbonise the electrical power sector by 2035 [19], a target (with amendments) recently brought forward to 2030 [20], [227]. Thus, in the next year or so, occasions of fossil generation being displaced by other sources, of which wind is likely to be important, are going to be necessary, and must become "business as usual" in a few years. Under such conditions, high wind output would be expected to drive down wholesale prices: storage assets under such conditions may well act to relieve network congestion.

Another set of changes under consideration, under the UK Government's Review of Electricity Market Arrangements [24], is a move to some kind of location-based pricing. Such a change would significantly alleviate the phenomenon of storage assets being incentivised to exacerbate congestions. The question of whether or not location-based pricing would be beneficial overall is beyond the scope of this thesis.

Alternative approaches which could relieve the problem of storage assets exacerbating network constraints could be to reconsider the firmness of connection of storage assets, a matter the subject of a distribution-level case study in Chapter 6 and Chapter 7. The electricity networks trade body has published guidance recommending "less firm" connections for distribution-connected storage assets than for other network users [102]. Alternatively, creations of local or regional ancillary services could potentially relieve this problem. The ESO is currently investigating options for constraint management [157], of which the "Grid booster" option would create a new market for batteries or other energy storage assets near to a constraint boundary (B6 being of most interest) to provide contingency or a post-fault service, as described in Chapter 3. This shows that the ESO believes storage assets have potential to alleviate network congestion, but that such assets would have to be incentivised to do so.

Even given the potential problem of storage assets (along with generators) being incentivised to exacerbate network congestion, at times and in some locations, this may be a problem worth tolerating if the presence of a fleet of such storage assets would deliver services of wider system benefit at other times.

5.5. Conclusions

The results – that there are occasions of simulated battery exports, even at times of very high Scottish wind availability, during which conditions windfarm curtailment is likely or certain -

find against the hypothesis: "*a rational battery, engaged in wholesale trades, will not export at times of high wind energy availability in Scotland, nor will it add to network congestion*".

During times of high wind availability in Scotland, there are likely to be times when batteries or other storage assets will export, if they are engaged in wholesale trades. If batteries are located in Scotland, such activity will exacerbate network congestion at these times.

This work highlights the potential adverse impacts of deployment of storage, despatched according to *system-wide* pricing, if such a 'national' price does not well-represent local or regional generation availability and output, or network constraints.

This work shows the need for suitable market and pricing environment for different assets, including storage assets, to promote their deployment being an aid rather than a hindrance to system operation.

The following chapter is a set of case studies at distribution level, set in southern Scotland, investigating the effect of simulated battery activity on local network conditions.

6. Chapter 6 Potential effects of batteries on Distribution Network Congestion in GB

Chapter summary

This chapter is set in a context of great interest in battery developers in connecting to distribution networks, and in which battery connections are taking up much of the currently unused network capacity, thus leaving less capacity for other users. This chapter examines the effect batteries, engaged in arbitrage, would have on network flows at EHV level at six locations of the southern Scotland distribution network. Network flows were estimated using data from SPEN Open Data Portal, and Balancing Mechanism data for windfarm output. The actions of a rational battery engaged in wholesale trades were simulated, as described previously in Chapter 4, for the same three 5-week periods during 2022.

This work found that suitably sized batteries at times would at times reduce, or at least not add to network flows, but more often would exacerbate both import and export network flows.

This finding holds for batteries sited on networks with both generation-dominated and demand-dominated power flows, and for batteries of differing durations. Unfortunately, network operators would be correct to assume that "worst case" behaviour from batteries, in terms of exacerbating maximum network flows, would be likely to occur at times. Network locations with a mix of generation and demand flows appear better able to tolerate battery activity than sites with flows strongly or entirely either demand or generation.

This work also found that, as the action a rational battery, engaged in wholesale trades, would vary with battery duration and round-trip efficiency, as well as an operator's chosen approach, it would thus be hard for a network operator to foresee. Actions of a simulated 12-hour flow battery at times fit better with network flows than those of short duration batteries, though in all cases there were occasions when all types of battery modelled would exacerbate import and export flows. There was no overall "ideal" size (in terms of MW capacity) of battery in terms of fitting well with network flows.

6.1. Context, introduction, and aims of this work

The context for this work is a great increase in interest from battery developers in connecting to distribution networks, as described previously in Chapter 3. As of November 2023, the DNO SP Energy Networks (SPEN)'s Scottish area had 135 MW of batteries "connected", and 4,450 MW of batteries "accepted to connect"; 700 MW of the latter's capacity was in a connection queue[58] [228]. A year later, by November 2024, deployment, actual and anticipated, had risen to 285 MW of "connected batteries, and just over 5,000 MW "accepted to connect". The battery roll-out evidenced in SPEN's Scottish licence area is a microcosm of the 80 GW of GB distribution systems-wide interest in battery connections described in Chapter 3. These connection agreements reduce the amount of network capacity available to offer other future connectees.

This work investigates the potential effect of a grid-scale battery, engaged in arbitrage, on maximum network flows on a distribution network, with a particular interest in locations with high distributed wind generation capacities. More specifically, this work aims to understand the expected nature of power flows that grid-scale batteries would cause, and whether these would be likely to increase or reduce maximum overall network flows. This work investigates the hypothesis:

> *"Deployment of suitably -sized distribution-connected batteries, engaged in wholesale electricity trades, will not increase congestion on distribution networks servicing residential load demand and windfarms."*

An intended application of this understanding is the question of whether a DNO, in this case SPEN, could safely and realistically assume anything other than "worst case" battery behaviour, i.e. that a battery would exacerbate both maximum import and maximum export network flows. A finding of "*batteries might not increase network flows*" could suggest that networks may be able to accommodate greater capacity of batteries than previously thought, in some circumstances.

[58] The DNOs' Embedded Capacity Registers have a field: "in a connection queue? (Y/N)" for each generator / storage project. Presumably the storage projects "accepted to connect" but not in a connection queue are at earlier stages of planning or development.

6.2. Overview of method and scenarios

The following two flowcharts summarise the main stages in this analysis, and the scenarios investigated. They are all explained in greater detail in the following sections.

6.2.1. Overview of method

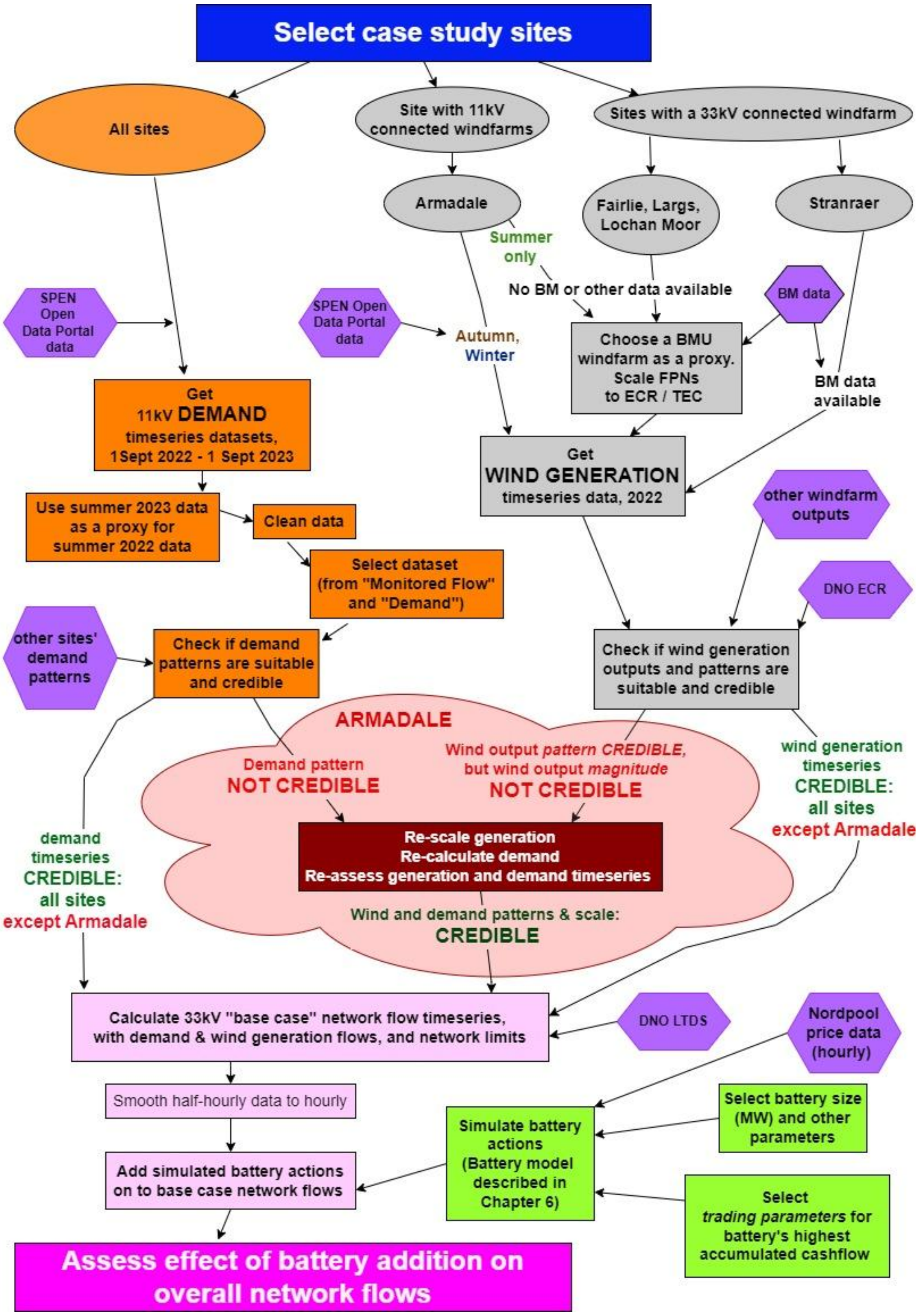


Figure 59 Overview of method for calculation of effect of a battery on DN power flows [59]

[59] Key: deep blue box – initial stage; purple hexagons – data sources; orange shapes – demand-data sites and operations; grey shapes – wind data sites and operations; pink cloud – additional operations for Armadale site only (the only site where wind data is from DNO); pale purple boxes – operations combining wind and demand data; bright green boxes – battery simulations ; bright pink box – final stage.

6.2.2. Overview of scenarios investigated

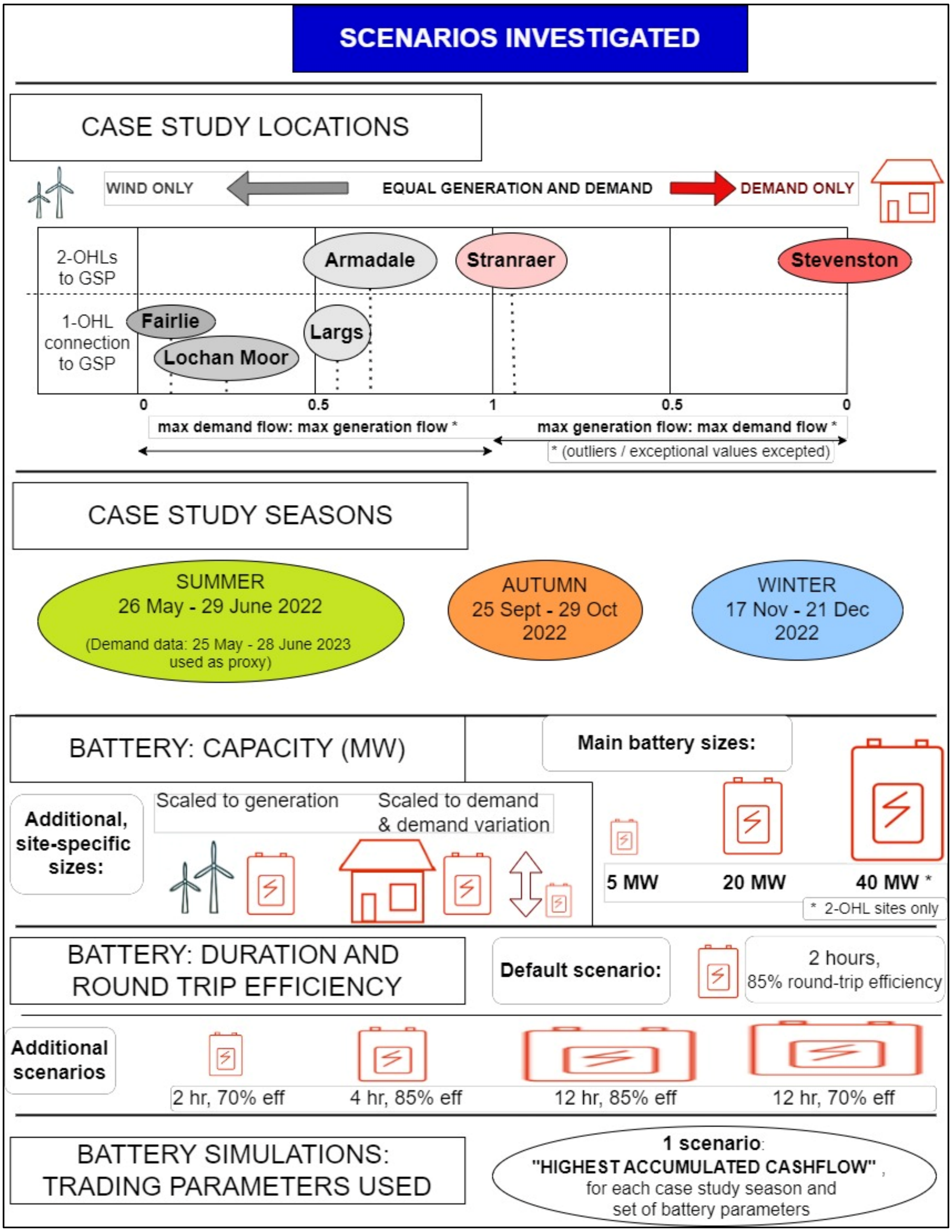


Figure 60 Overview of scenarios investigated: location, season, battery capacity and other batter parameters

6.3. Case study locations and data description

6.3.1. Case study locations

Six locations in southern Scotland were chosen for analysis.

The locations were selected to include some of the following features: varying degrees of wind penetration; network flows nearing network limits; examples of village and town demands; one "demand-only" circuit, for comparison; locations with both "N" (i.e. only a single connection from the demand centre to GSP) and "N-1" security (i.e. two separate branches connect the demand centre to GSP). The main features of these network locations are listed in Table 30 and Table 31. The circuit diagrams for all locations are taken from SPEN's LTDS [229], reproduced in Chapter 6 Annex 1, and shown schematically in Figure 61 below.

Table 30 Overview of case study sites

Case study location	Main loading on the 33kV line
Armadale	Demand and generation, similar magnitude
Fairlie	Strongly generation dominated
Largs	Generation-dominated but also significant demand
Lochan Moor	Strongly generation dominated
Stevenston	Demand only
Stranraer	Demand-dominated but also significant generation

Table 31 Demands and generators at case study locations

Case study	Demand(s) (all connected at 11kV)	Generation			No. of connections from GSP to demand bus
		Generator	**Point of Connection**	**Voltage**	
Armadale	Armadale town	4 small windfarms	Armadale bus	11kV	2
Fairlie	Fairlie village	Kelburn A windfarm	Fairlie A SWS	33kV	1
Largs	Largs town	Kelburn B windfarm	Fairlie B SWS	33kV	1
		2 small hydro stations	Largs bus	11kV	
Lochan Moor	Auchneel village Barrhill village	North Rhinns windfarm	Lochan Moor SWS	33kV	1
Stevenston	Stevenston town	None	-	-	2
Stranraer	Stranraer town	Glenchamber windfarm	Glenluce SWS No. 1	33kV	2

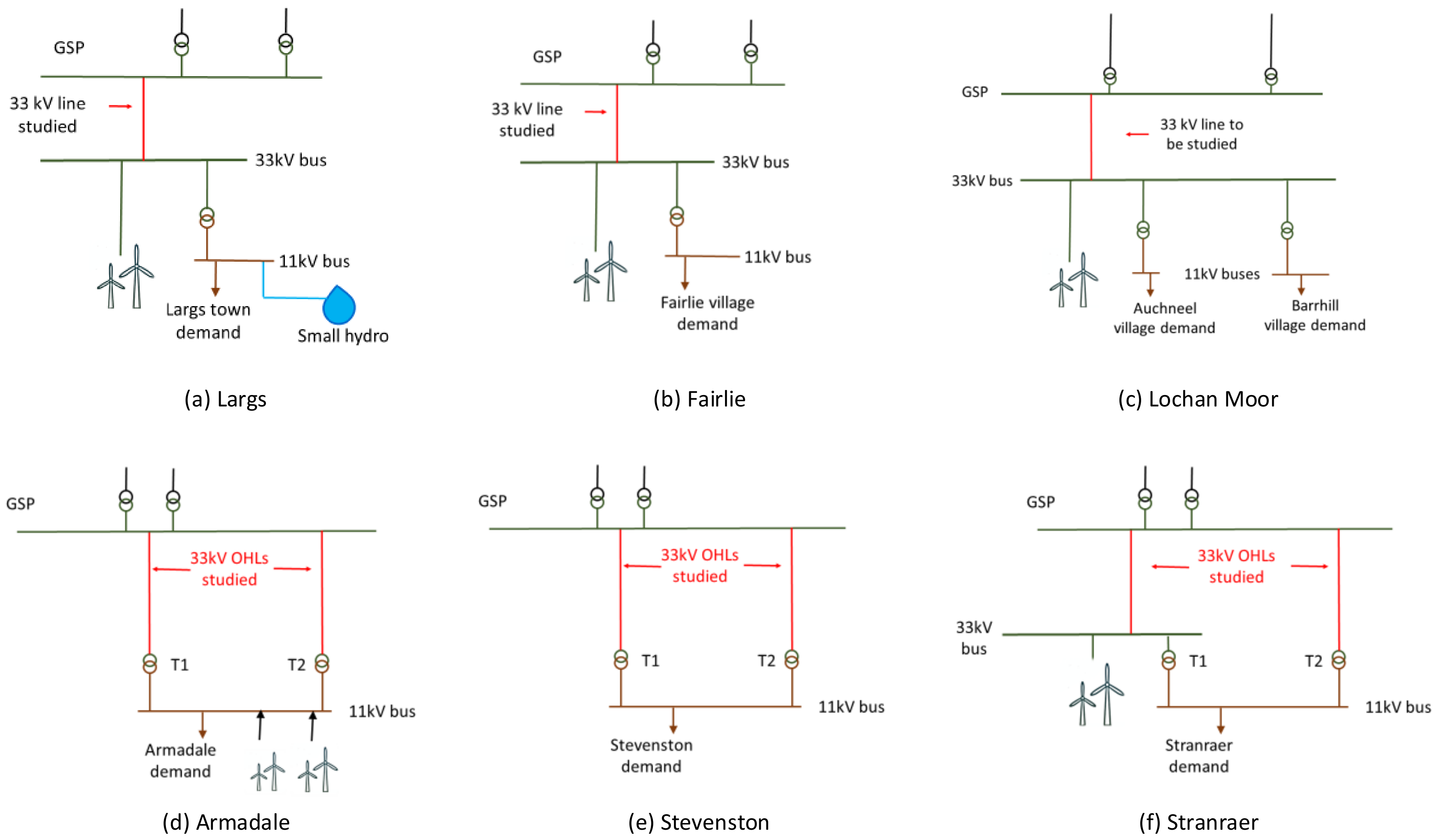


Figure 61 Circuit diagrams for all case study locations

Figure 62 is a map of the case study locations. (Proxy windfarms are discussed below, in section 6.3.3.)

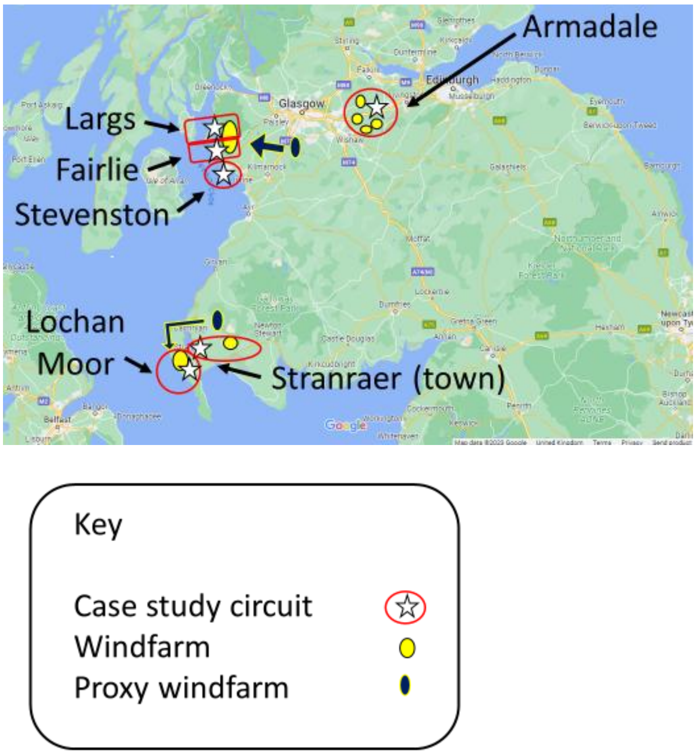


Figure 62 Map of case study locations

Table 32 lists the MVA limits of the 33kV circuits of interest, and, where relevant, of transformers.

No "short-term ratings" for overhead line (OHL) capacity are applicable.   One DNO (Northern Powergrid), states:

"*Unlike cables and transformers, due to their short thermal time constant, overhead lines have neither cyclic nor emergency ratings, they only have continuous ratings that are applicable in the three seasons (summer, winter and spring/autumn*)." [230]

Table 32 Summary of circuit and transformer limits, and feeder distances, for case study locations [229], [231]–[233] .

Case study	Bus (33 kV) / SPEN LTDS Circuit listing	GSP / SPEN LTDS Circuit listing	Other connection point	Cct.	Circuit limits (all 33kV), MVA			Distance km	Transformer limits, MVA
					Summer	Autumn	Winter		
Lochans Moor	Lochans Moor SWS / LOHM3-	Glenluce GSP / GLLU3A1	-		21.6	21.6	22.4	14.52	-
Largs	Fairlie B SWS / FAIR3B	Saltcoats B GSP / SACO3B2	-		20.9	20.9	21.74	16.463	-
Fairlie	Fairlie A SWS / FAIR3A	Saltcoats B GSP / SACO3B1	-		20.86	20.86	20.86	15.131	-
Armadale	Armadale Primary 1 / ARMAT1	Bathgate GSP / BAGA3A1	-	A	19.71	19.71	20.86	1.84	24
	Armadale Primary 2 / ARMAT2	Bathgate GSP / BAGA3R	-	B	19.71	19.71	20.86	1.85	24
Stranraer	Glenluce SWS No. 1/ GLLUX1	Glenluce GSP / GLLU3B	-	A	19.71	19.71	24.63	15.1	-
	Glenluce SWS No. 1/ GLLUX1	-	Stranraer Primary 2 / STRAT2	A	S/C	S/C	S/C	-	24
	Stranraer Primary 1 / STRAT1	Glenluce GSP / GLLU3A2	-	B	19.71	19.71	24.63	13.6	24
Stevenston	Stevenston Primary 1 / STEVT1	Saltcoats A GSP / SACO3A1	-	A	16.29	16.29	16.29	3.74	21
	Stevenston Primary 2 / STEVT2	Saltcoats A GSP / SACO3A2	-	B	19.71	19.71	20.86	3.66	21

6.3.2. Network flow data at 11kV level, from SPEN Open Data Portal [234]

Various metrics of circuit flows at the 11kV buses were examined at the case study locations.

All demands are from 11 kV bus listings. Lochan Moor demand is composed of demand from the two small settlements of Auchneel and Barrhill, each of which has its own 11kV bus. All other case study locations have a single demand from a bus of the same name.

6.3.2.1. Data description

Datasets from 1 September – 31 December 2022, and 1st January – 31st August 2023, were examined. No earlier data were available. The 2022 datasets were downloaded from the portal during 4 - 8 September 2023, and the 2023 datasets on 17 - 18 October 2023.

The SPEN data portal does not list flows on individual 33kV lines, though it lists overall flows to GSPs, which were not used.

The data portal lists the following parameters at all 11kV buses: Monitored Flow (MW), Monitored Flow (MVAr), Current (Amps), Generation (MW) and Demand (MW). These datasets were used in all following analysis[60].

Demand flows are listed as positive, and generation negative, when not zero. Monitored flows are positive when demand-dominated and negative when generation-dominated.

Two locations, the small villages / hamlets of Barrhill and Auchneel (which are part of the Lochan Moor overall case study location), show slight negative demands (up to around 0.5 MW) at times, especially in the summer. Rooftop solar may well contribute to such reverse power flows, but some occur at night, and their source is unclear.

Monitored flow and demand data are listed to 3 decimal places, but generation to only whole numbers of MWs. Only one of the case study locations, Armadale, has generation data with values of significant magnitude listed on the SPEN Data Portal. Examination of datasets at all six locations found the following:

[60] SPEN's data portal site stated in 2025: *"The 'Network Flow: Power, Current and Embedded Generation' dataset details historically measured average and reactive power flows, current and provides indicative demand/generation output for each Grid and Primary network group for our SP Manweb (SPM) and SP Distribution (SPD) licence areas, for each half-hourly period*." [285]

$$Demand\ (MW) + Generation\ (MW) \approx Monitored\ Flow\ (MW) \tag{6.1}$$

$$Demand\ (MW) + Generation\ (MW) - Monitored\ Flow\ (MW) \leq |0.7\ MW| \tag{6.2}$$

The data are publicly available. SPEN are understood to have been "anonymised"[61] data where necessary, so some metrics may have been changed by SPEN before release.

6.3.2.2. *Data "cleaning" and data display, 2022-2023.*

There were some instances of missing data and duplicated data, which needed addressing to use the datasets. There were also a few brief instances when SPEN data portal metrics fell to zero or other anomalous values, or held a fixed value for hours, or even days or weeks. Some such instances were assumed to be monitoring faults, rather than a descriptions of what actually happened. In some of these instances, the data portal values were "cleaned" i.e. replaced with a value deemed more credible, with particular attention to the case study time periods which are used in more detailed analysis as described in the following chapters. Data "cleaning" was also important preparation for some of the analysis detailed in later sections.

Details of which data were replaced, and which retained, are described and tabulated in Chapter 6 Annex 2. Timeseries "Monitored Flow (MW)" charts for all case study locations, as downloaded from SPEN, and after "cleaning", are displayed in Chapter 6 Annex 3.

6.3.2.3. *Spring and summer 2022*

It was desired to have demand and circuit flow data for a period in early summer 2022 (26 May – 29 June 2022), for use with a time window for which wholesale price data and simulations for battery behaviour had been performed. However, SPEN data were first made available in August 2022, after the desired time window.

It was considered that demand data are likely to be fairly similar from one year to the next, at the same time of day and day of the week. Thus, SPEN data from May and June 2023 are used as a proxy for likely demands and "monitored flows" one year earlier. The dates are shifted by one day, to retain the same day of the week.

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[61] SPEN state: "*This data has been triaged to remove information pertaining to individual customers or where the dataset contains sensitive information. This dataset is updated on a weekly basis*." [285]

6.3.2.4. Selection of dataset to describe 11kV demand flows

At all locations, demand flows could potentially be described using either the "demand" dataset, together with the "generation" datasets to describe any 11kV-connected generation. Alternatively, 11kV flows could be described in aggregate by the "Monitored Flow" dataset.

For all locations other than Armadale, "Monitored Flow" datasets were used to represent "demand net of any generation". Further information about these datasets is given in Chapter 6 Annex 4.

6.3.3. Wind generation data

In order to ascertain the flows on the parts of the circuits of interest, it is necessary to find or estimate the outputs from the connected windfarms.

At Armadale, the SPEN Data Portal listed aggregate output from all generation at that bus, i.e. the four small connected windfarms, covering the period of autumn 2022 to autumn 2023.

Fairlie, Largs, Lochan Moor and Stranraer case studies circuits all have windfarms connecting at 33kV level, whose outputs are not displayed on SPEN's Open Data Portal. Unfortunately in most cases (all but Stranraer) there is no publicly available source of timeseries wind generation data.

Wind energy data are available for windfarms which participate in the Balancing Mechanism BM [235], [236]; such data are available for the whole of 2022. For Stranraer case study, the connected windfarm, Glenchamber, is a BM participant, so data for that windfarm were used. The other connected windfarms (North Rhinns for Lochan Moor, Kelburn A and B for Fairlie and Largs, respectively, and the four small windfarms connecting at Armadale) are not BM participants. In these cases, a nearby windfarm was used as a proxy, with its output scaled appropriately. Several windfarms were considered, seeking a windfarm that is ideally located nearby (to experience the same weather), has similarly-sized turbines, and does not suffer periods of outages or low performance. The candidate windfarms are tabulated in Chapter 6 Annex 5.

Whitelee windfarm was used as a proxy for Kelburn A and Kelburn B windfarms, connected to Largs and Fairlie case study circuits. Kilgallioch windfarm was used as a proxy for North Rhinns windfarm, connected to Lochan Moor case study circuit.

Armadale case study location required a proxy windfarm for the summer 2022 case study only, because SPEN data for generation were only available from autumn 2022 onwards. Whitelee, scaled according to connected the aggregate capacity of the its connected windfarms, was used.

In all cases where BM data were used, the 'Final Physical Notifications' (FPNs, i.e. the estimated output of the windfarm before any curtailment instructions) datasets were used.

6.4. Circuit flows during case study periods. Base case: current arrangements (no batteries)

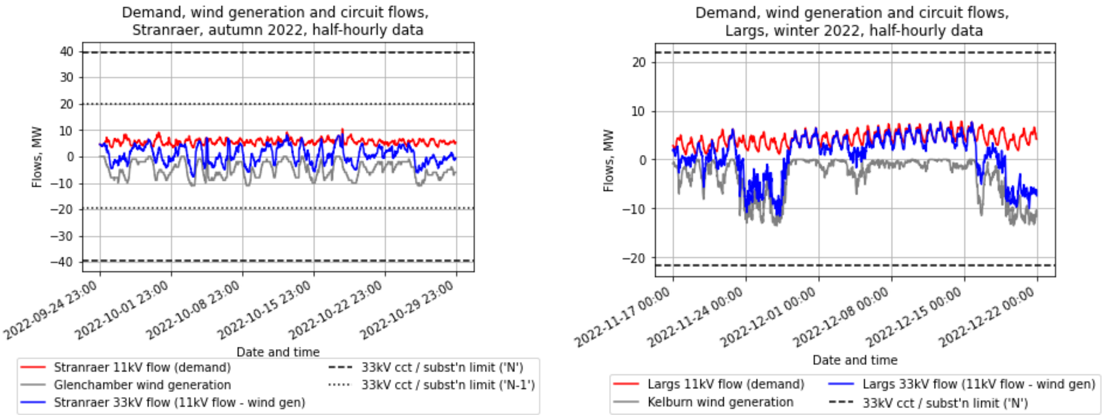
6.4.1. General description: combinations of demands and wind data

For each case study, the overall flows via the 33kV circuits, from demands, generation, and the sum of both, were evaluated, for the three 5-week case study periods as used in the previous chapters, namely: "autumn" (25 Sept-29 Oct 22), "winter" (17 Nov – 21 Dec 22) and "summer" (26 May – 29 June 22).

As described above, for the summer 2022 case study, demand data for 2023 (between the dates 25 May – 28 June 2023, inclusive) were used as a proxy for 2022 demand during 26 May – 29 June 2022; wind generation data were all for the correct dates in 2022.

Reactive power flows for "Monitored Flow", reported on SPEN's Open Data Portal were shown, and used together with SPEN's reported values of real power, to calculate MVA power flows. These MVA flows generally differed little from the MW power flows. Considering the considerable uncertainty in reactive power output from the windfarms, it was decided to neglect reactive power flows, and only to consider real power flows.

Chapter 6 Annex 6 displays the overall power flows at 33kV level for each circuit, during the autumn, winter and summer case study periods. For Armadale, Stranraer and Stevenston, these flows represent the total flows across both circuit branches. The flows are shown together with the relevant 'N', and where applicable, 'N-1' circuit limits. Figure 63 shows two examples, for Stranraer and Largs.



(a) Stranraer, autumn (b) Largs, winter

Figure 63 Time series 11kV substation flow, wind generation, and combined 33kV flows. Half-hourly resolution. (a) Stranraer, autumn 2022; (b) Largs, winter 2022

6.4.2. Armadale scaling

The dataset for Armadale is the only one with significant 11kV-connected generation outputs reported by SPEN.

Unfortunately some limitations of these datasets were found:

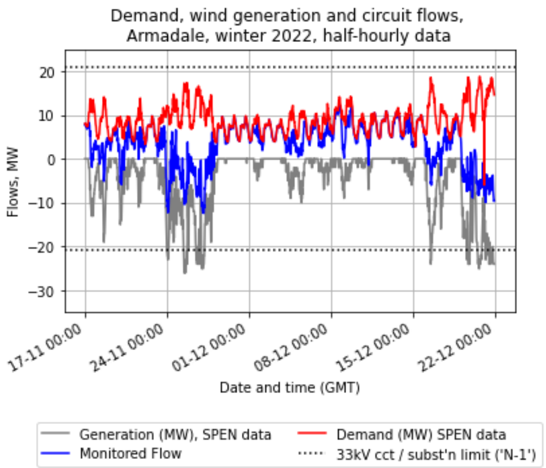
- The diurnal patterns of SPEN's open data portal *demand data* at Armadale *were not considered credible* for much of the duration.
- The *generation* patterns reported on the Open Data Portal were credible in *timings* of outputs, being very similar to wind output from other locations studied. However, the *magnitude of reported output* was *not considered credible*: SPEN Open Data Portal's lists maximum output as 26 MW, which significantly exceeds the total capacity of all four generators connected at that bus (17.92 MW) recorded on SPEN's ECR and LTDS documents.

SPEN's "Monitored Flow" values for Armadale were assumed to be correct and were not amended (beyond data cleaning, described above).

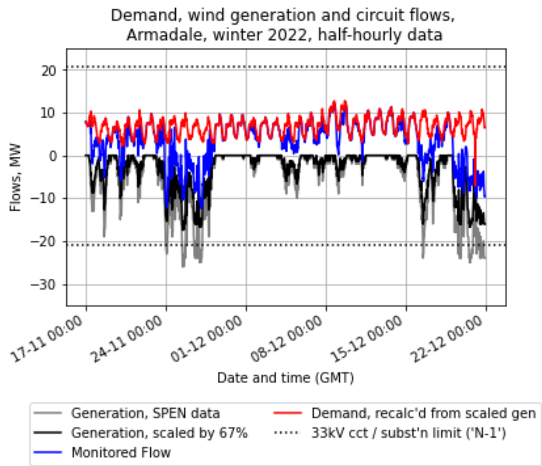
Generation and demand were recalculated, in an attempt to obtain credible timeseries for both. The generation pattern was retained, but it was reduced in magnitude. Demand was recalculated as the difference between Monitored Flow and Generation, at every timestep. Different scaling factors were trialled, and a generation scaling factor of 67% was selected, as the one which resulted in the most credible demand pattern. This process in described in greater detail in Chapter 6 Annex 7.

The rescaled generation (maximum value of 17.42 MW during the windiest period of three case study periods) is considered highly credible, being 97% of the windfarms' combined capacity, as listed on the ECR; this is further discussed in Chapter 6 Annex 7.

Armadale circuit flows, original and after rescaling, for the winter case study period, are shown below.



(a) Monitored Flow data as downloaded from SPEN (before rescaling)



(b) Monitored flow data rescaled

Figure 64 Armadale demands, generation, and overall "Monitored Flows" winter 2022. (a) before and (b) after rescaling.

For the summer period, rescaled demand was calculated in the same way as for the autumn and winter periods. However, the SPEN generation dataset, describing wind output in 2023, was not considered appropriate to use as a proxy for 2022, as the weather would be different. Thus it was necessary to use a proxy windfarm, scaled by maximum output. Whitelee windfarm was chosen: it had very similar timings of periods of windy and calm weather as the Armadale generation dataset during the autumn and winter case study periods.

Summary of maximum circuit flows

A summary of the maximum demand and generation flows on the 33kV sections of the circuits is given in Table 33.

(These maximum flows are required in Chapter 7 , in which batteries are sized according to available “network headroom, taking into account circuit capacity and maximum flows from generation and demands. Further details on the selection of “normal” and “abnormal” values are given in Chapter 7 Annex 1.)

Table 33 Case study locations: max generation [234], [235], demands [234], 11kV "Monitored Flows", Sep22-Aug23, and circuit & transformer limits [231], [232]

Case study place	Circuit loadings	Windfarm	Windfarm capacity & connection voltage	Windfarm modelled	Windfarm data source	No. ccts. to GSP	Max 2022 generation, (MW) [62]	11kV bus max flows (MW): "normal" /("abnormal")[63]		Circuit or transformer limit (MVA): summer / autumn / winter (S: / A: / W:)	
								Max 22/23 "Demand"	Max 22/23 "Monitored Flow" [64]	'N'	'N-1'
Fairlie	Demand & wind	Kelburn A	14 MW, 33kV	Proxy - Whitelee	BM	1	14	1.495 / (5.885)[65]		S, A, W: 20.86	-
Largs	Demand & wind	Kelburn B	14 MW, 33kV	Proxy - Whitelee	BM	1	14	8.362	7.805	S, A: 20.9 W:21.74	-
Lochan Moor	Demand & wind	North Rhinns	22 MW, 33kV	Proxy - Kilgallioch	BM	1	22	5.002	4.889	S, A: 21.6 W: 22.4	-
Stranraer	Demand & wind	Glen-chamber	27.5 MW, 33kV	Actual	BM	2 [66]	13	11.764 / (24.756)		S, A: 39.42 W: 48.63. [67]	S, A: 19.71 (cct) W: 24 (transformer)
Stevenston	Demand	-	-	-	-	2	0	13.354 (19.791)		S, A: 36.00 W: 37.15	S,A,W: 16.29 (branch 1) / S, A: 19.71, W: 20.86 (branch 2)
Armadale	Demand & wind	several	Several, 17.92 MW, 11kV	Actual: aut',winter Proxy: Whitelee, summer	SPEN: autumn, winter. BM: summer	2	26 (raw)[68] . 17.42 / 17.91 (rescaled)	21.50 (raw) 13.408 (re-calc'd)	12.01 import (demand), 13.91 export (generation)	S, A: 39.42 W: 41.72	S, A: 19.71 W: 20.86

62 BM generation data: maximum values are for the whole of 2022. SPEN data portal, all metrics: values are for the period of available data, Sep-Dec 22 & Jan-Aug 23.

63 Both Stevenston and Stranraer have a number of short duration "spikes" in MF & demand, considered "abnormal". Details of the selection process for the "normal" values are given in Annex 1 of Chapter 10.

64 All max "Monitored Flows" are demand flows, unless otherwise stated (Armadale only).

65 In Fairlie, exceptionally high demands of 1.5-5.9 MW occurred over a few days: 2 May, and 26 June - 1 July, 2023.

66 Glenchamber windfarm is attached to a 33kV bus on one of the circuits between Stranraer town and Glenluce GSP.

67 It is assumed that Glenchamber windfarm can export both through the single 33 kV circuit branch direct to GSP, and also via Stranraer town 11kV bus and the other 33 kV circuit branch to GSP.

68 Armadale generation and demand flows were rescaled / recalculated, as described in Section 6.4.2, and Annex 7. 17.42 MW is the max generation estimated to have occurred during case study periods. Assuming the same generation pattern as Whitelee, there would have been a maximum output of 17.91 MW in Jan & Feb 2022.

6.5. Effect of an additional battery to network flows: Method

6.5.1. Overview

A short duration battery with round trip efficiency of 85% is simulated, as described in Chapter 4. The battery simulations were run for the same three 5-week case study periods, using the same real price data from 2022. For each case study period, the single highest performing battery trading scenarios (the scenarios which accrued the maximum overall net revenue from the trades) were selected.

Circuit flows at all the locations, for the autumn, winter, and summer case studies, for "base case", conditions i.e. without any battery, were obtained, as described in Section 6.4.

This work superimposes simulated flows from battery activity onto these base-case circuit flows.

For ease of modelling network flows together with simulated battery activity, two minor modifications were performed. First, the network data were smoothed from half-hourly to hourly resolution. This is because the battery simulations are of hourly resolution (because they use a wholesale price dataset which has hourly, not half-hourly prices). This processing caused little change to the network flow data profiles, except on occasions of short-duration unusual events, mainly data spikes, which appear lower in magnitude at a lower temporal resolution.

To fit with the battery simulation datasets, which were in European clock time, a one-hour time-shift was performed, i.e. starting all runs at 11pm clock time the night before the first day, and finishing at 11pm on the last day of the run. The charts at 1-hour resolution, starting and finishing one hour earlier, are shown in full in Chapter 6 Annex 8, for comparison with the half hourly charts in Chapter 6 Annex 6.

6.5.2. Locations of battery connection

This work is intending to look at overall network flows, with and without a battery, and compare the magnitudes of these flows to the respective circuit limits.

For all the locations with a windfarm connected at 33kV level, the scenario chosen here has the battery connected at the same bus as the windfarm. For the other two locations, Armadale and Stevenston, the battery connects to a new bus on one of the 33kV lines. Figure 65 is a schematic diagram showing the battery siting at all locations.

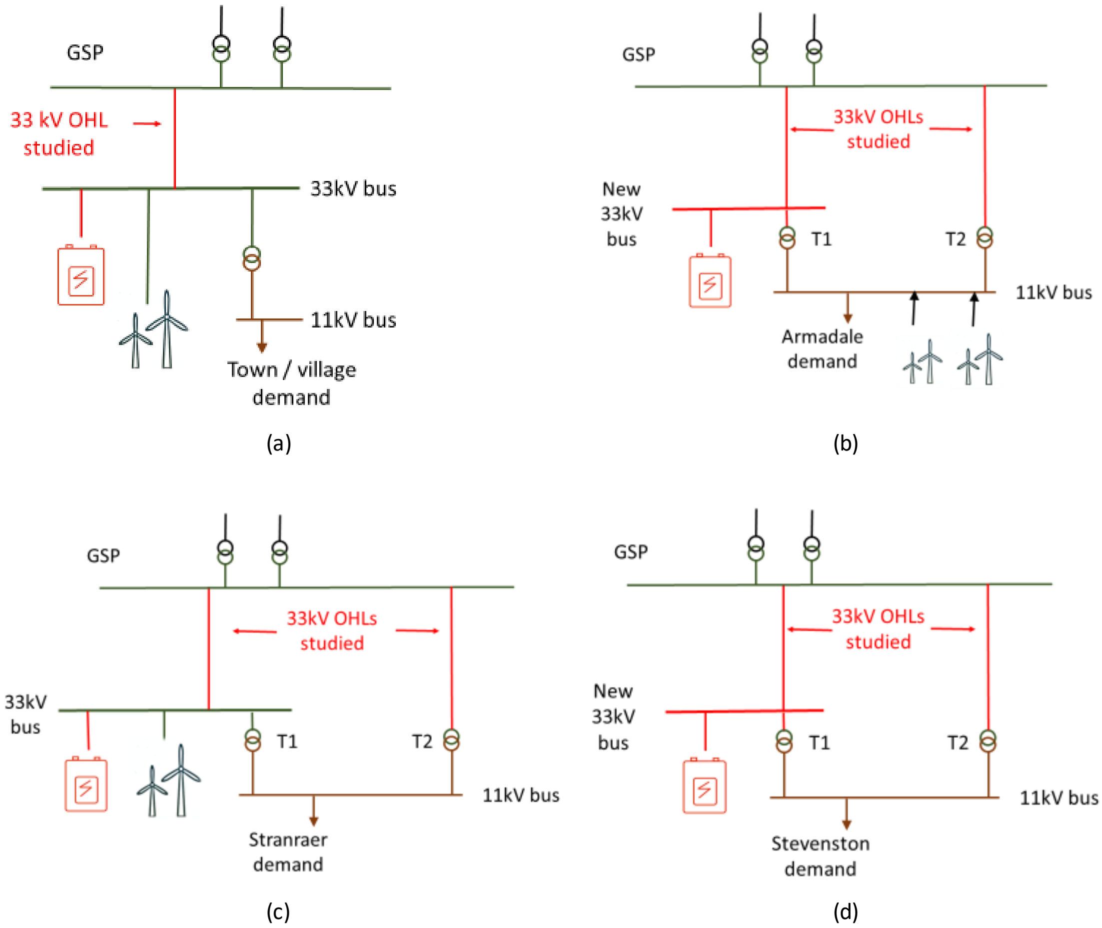


Figure 65 Battery locations, near (a) Fairlie, Largs and Lochan Moor; (b) Armadale; (c) Stranraer; (d) Stevenston

The circuit and transformer limits are previously set out in Table 32.

Stevenston has lower capacity in circuit A than circuit B, by around 4 MVA; Stranraer and Armadale have the same capacity in both lines “A” and “B”. Details of which line the battery connects to are important in the following chapter, which explores how limitations of circuit capacity would affect battery actions and cashflows.

6.5.3. Battery sizing

A 1 MW battery would have little effect on circuit loadings, so the battery is scaled up, by several different factors, as shown in Table 34.

Table 34 Battery sizes modelled with network flows

Aggregate battery capacity (MW)	Reason	Locations used	No. of network connections to GSP
3 MW **5 MW**	Comparable with variation in demand at larger-demand locations	Fairlie, Largs, Lochan Moor	1
		Armadale, Stranraer, Stevenston	2
20 MW	Approximate capacity of a single OHL branch, most circuits.	Fairlie, Largs, Lochan Moor	1
		Armadale, Stranraer, Stevenston	2
40 MW	Approximate capacity of both OHL branches, for the three 2-feeder locations[69]	Armadale, Stevenston, Stranraer	2
Maximum generation	To simulate the effect of sizing batteries to match outputs from the relevant windfarm	Fairlie, Largs, Lochan Moor	1
		Armadale, Stranraer[70]	2
Maximum demand	To simulate the effect of sizing batteries to match the highest value of demand on that circuit	Largs, Lochan Moor[71]	1
		Armadale, Stevenston, Stranraer	2
Demand variation	To simulate the effect of sizing the battery to match in-season variations in demand flows	Largs, Lochan Moor	1
		Armadale, Stevenston, Stranraer	2

"Maximum generation", "maximum demand" and "demand variation" are all specific to the location and case study period. The values modelled are detailed in Chapter 6 Annex 9.

[69] One location, Stevenston, has aggregate OHL capacity ~ 4 MVA smaller.
[70] Stevenston has no generation
[71] Fairlie has minimal demand

6.5.4. Battery trading: scenarios and parameters

This exercise was performed for a 2-hour battery having 85% overall round-trip efficiency.

Brief inspection of batteries of different duration and round trip efficiency was conducted, for parameters listed in Table 35.

Table 35 Battery durations and round-trip efficiencies modelled

Battery duration	Battery round-trip efficiency	Potential scenario
2 hours	85%	Lithium-ion battery, allowing for “normal” losses from battery and ancillary equipment
2 hours	70%	As above, with higher losses
4 hours	85%	Lithium-ion battery, allowing for “normal” losses from battery and ancillary equipment
12 hours	85%	Not currently available commercially. Included for comparison, to separate modelled effect of duration and round trip losses.
12 hours	70%	Flow battery, “normal” losses from battery and ancillary equipment

In each case, for each season, the battery trading parameters were chosen to allow the greatest accumulated cashflow over the season. These parameters are tabulated in Chapter 6 Annex 10.

As in Chapter 5, the simulations all assumed an initial State of Charge for the autumn and winter runs was 0.5.

For the summer runs, different initial SOCs were used, to avoid a significant price correction at the end of the run, due to the final wholesale price being unusually high compared with prices in the rest of the run. Thus, the initial SOC was chosen to be close to that at the end of the run. 2-hour batteries had an initial SOC of 0; the initial SOC for other batteries in summer is shown in Chapter 6 Annex 10.

6.5.5. “Worst case” network flows

Network flows with additional battery activity are displayed together with the applicable “N” and “N-1” network limits. In addition, “Worst case” imports and exports, i.e. the battery capacity, added to the highest overall import, and highest overall export, during each case study period, is also shown, to illustrate whether there are occasions of batteries fully exacerbating existing maximum network flows.

6.6. Results: effect of an additional battery on overall network flows

Magnitudes of projected 33kV circuit flows are displayed, with additional simulated battery flows, shown in bright green.

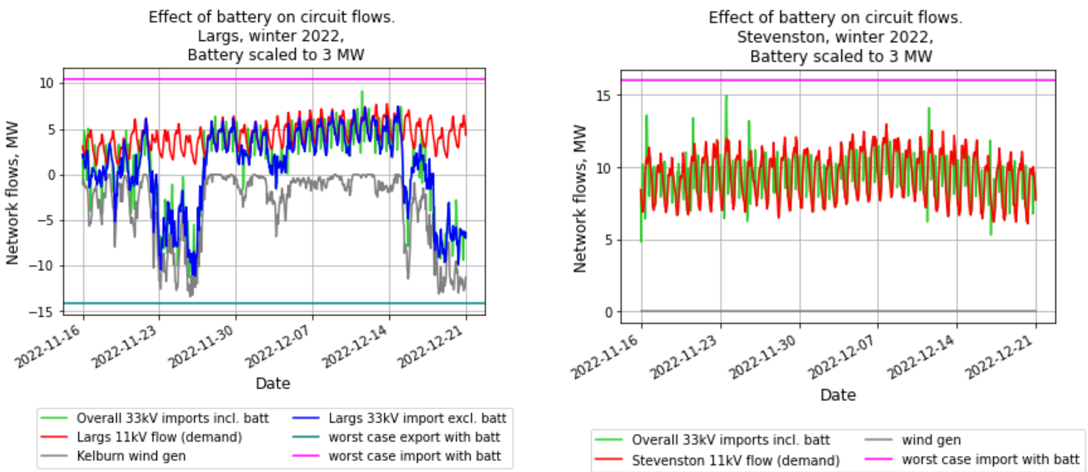
6.6.1. Base case battery: 2 hours duration, 85% round-trip efficiency

The effects of an additional battery, under scenarios as described above, would have on overall circuit flows, are presented in Chapter 6 Annex 11 and Chapter 6 Annex 12.

6.6.1.1. Fixed battery MW sizes

Annexes 11A and 11B in Chapter 6 Annex 11 show resultant circuit power flows in the 33kV OHLs, in scenarios of an additional 3 MW and a 5 MW battery, respectively. Results are presented for all six locations and all three seasons.

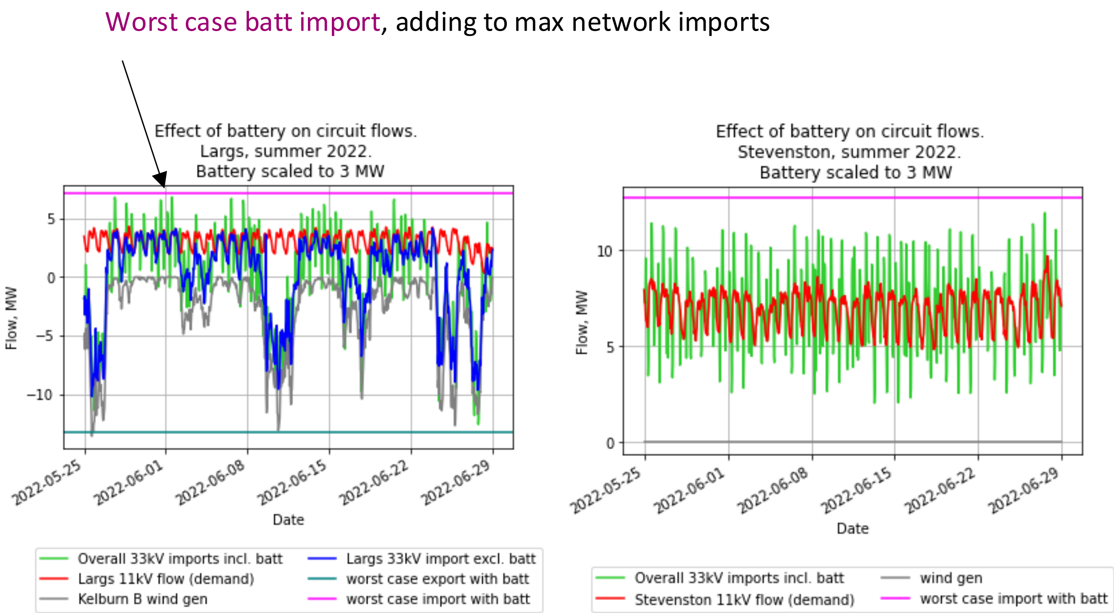
Figure 66 shows the smallest battery size simulated, most often *reducing* network flows, at Largs (a town with a large windfarm), and demand-only Stevenston town, during most of the winter case study period. Similar results for Armadale and Stranraer, for 3 MW and 5 MW batteries, are shown in Annex 11A and 11B (of Chapter 6 Annex 11). These results are discussed in Section 6.7.1.



(a) Largs, winter (b) Stevenston, winter

Figure 66 3 MW battery in winter, generally reducing network flows, Largs and Stevenston.

However, Figure 67 shows that during the summer case study period, the same battery would generally *exacerbate* import flows, at both Largs and Stevenston. At Largs, the battery would also, occasionally, exacerbate maximum export flows, results also found at the other sites. At Largs, imports occasionally approached the “worst case” import value, i.e. a battery import occurred at a time of high, approaching maximum overall demand and also low wind conditions. These results are discussed in Section 6.7.2.



(a) Largs, summer (b) Stevenston, summer

Figure 67 Effect of a 3 MW battery in summer, generally increasing network import flows, Largs and Stevenston.

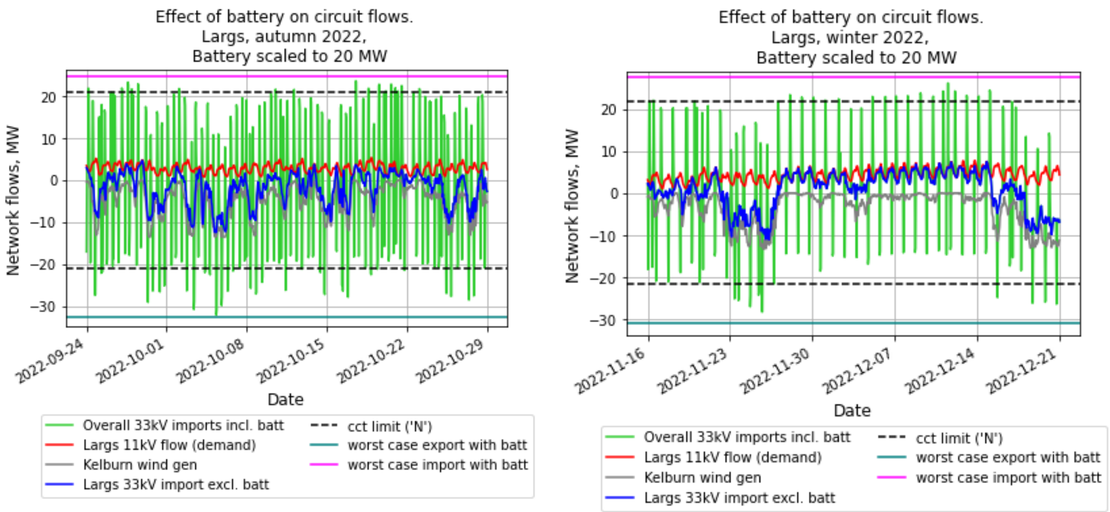
Simulations for “larger” batteries, sized at 20 MW and, for the three “two-feeder” locations (Armadale, Stranraer and Stevenston), 40 MW, with full results in Annex 11C and 11D (of Chapter 6 Annex 11) respectively. While clearly overall network flows could not be allowed to exceed network “N” limits, it is useful to present large simulated battery flows, in relation to such limits, to see the extent of any flows exceeding network capacity. The following chapter, Chapter 7, explores scenarios of flows from oversized batteries being restricted to available network capacity.

The overall 33kV power flows for Largs in autumn and winter, with an added 20 MW battery, are shown below in Figure 68. Regarding the 33kV flows,

- Export flows, compounded by battery exports, would often exceed network limits in the autumn.
- Imports flows, exacerbated by battery imports, would also occasionally exceed network limits in autumn;

- There are instances of near “worst case” imports and exports, in autumn, with battery actions exacerbate already high flows.
- Such events are projected to occur in the winter as well, but much less often.

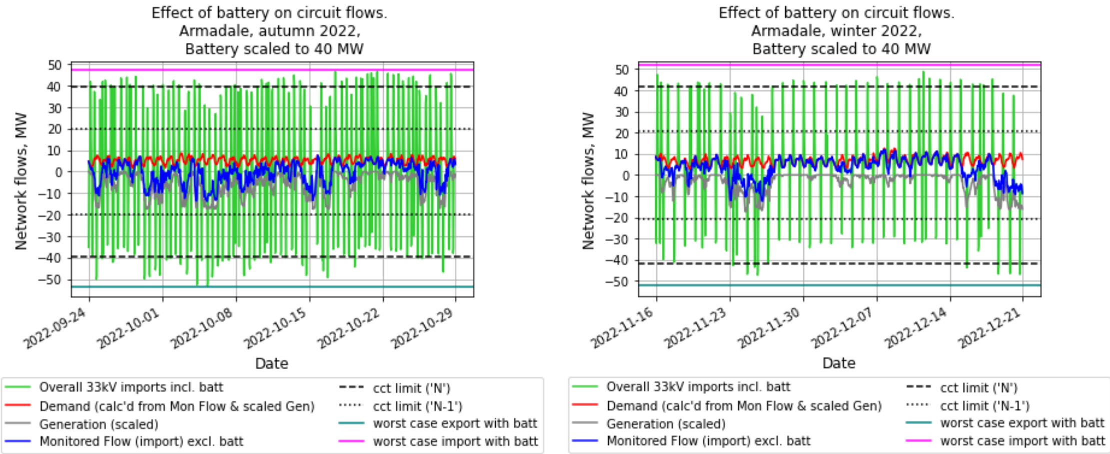
Similar results were found at Fairlie and Lochan Moor, sites which also have a large connected windfarm. At Armadale and Stranraer, export flows in autumn, in aggregate across both feeders, would often exceed the limit of one of the feeders (i.e. “N-1” conditions) but not the aggregate capacity of both feeders.



(a) Autumn (b) Winter

Figure 68 Effect of a 20 MW capacity battery on 33kV circuit flows at Largs, in (a) autumn and (b) winter case study periods.

Annex 11D of Chapter 6 Annex 11 contains the projected power flows at Stevenston, Stranraer and Armadale, with an additional 40 MW of battery capacity across both circuits. For Armadale, shown in Figure 69, there are occasions of overall 33kV flows exceeding the aggregate capacity of both feeders, more often occurring for exports in the autumn, the windiest season studied.



(a) autumn (b) winter

Figure 69 Effect of a 20 MW capacity battery on 33kV circuit flows at Armadale, in autumn and winter case study periods

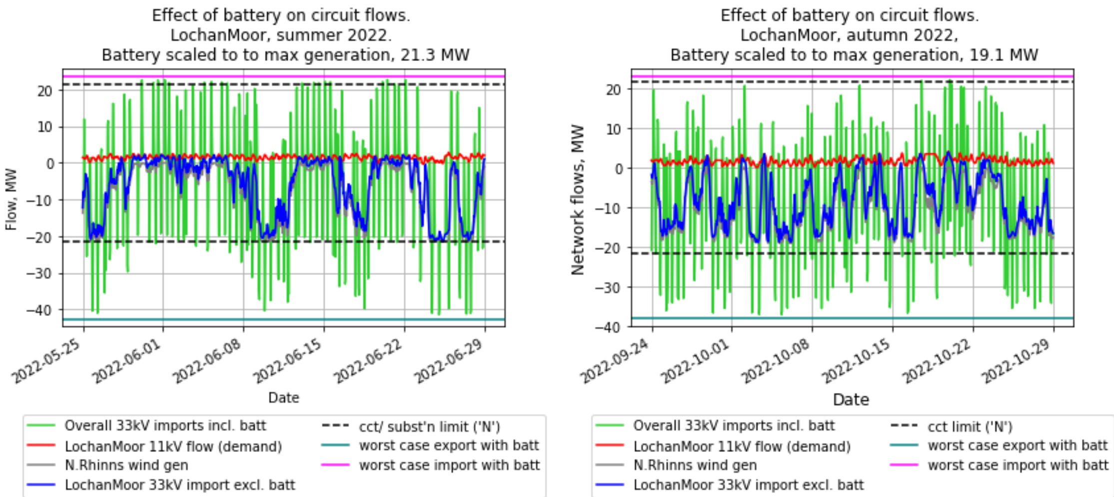
6.6.1.2. *Location-specific battery sizes*

Further simulations were performed with batteries sized to the location-specific

- maximum generation,
- maximum demand, and
- variation of demand (all specific to the case study),

which are displayed in Chapter 6 Annex 12: Annex 12A, 12B and 12C respectively.

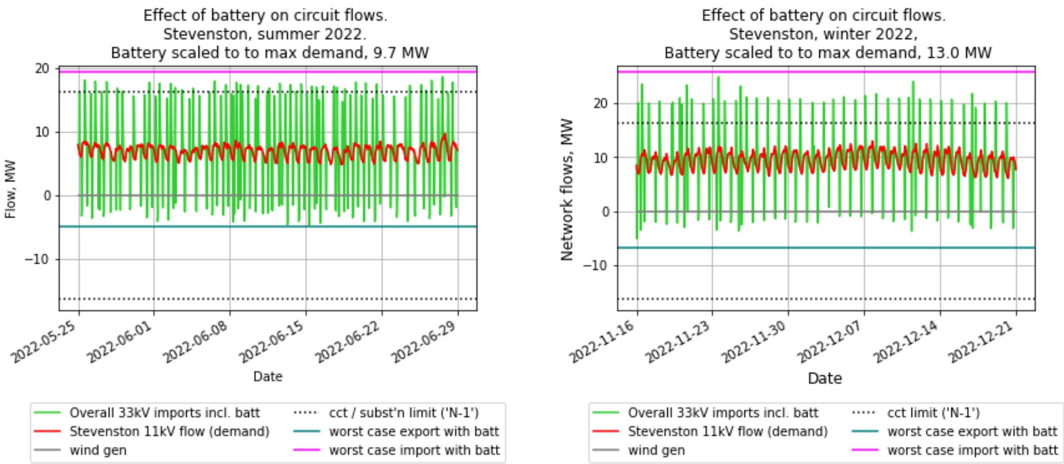
Scaling a battery to size with the windfarm does not reduce circuit flows, but greatly increases them: examples below are included for generation-dominated Lochan Moor, in summer and autumn, in Figure 70.



(a) Lochan Moor, Summer (b)Lochan Moor, Autumn

Figure 70 Effect of a battery, sized to the windfarm's capacity, on overall network flows. Lochan Moor, summer and autumn

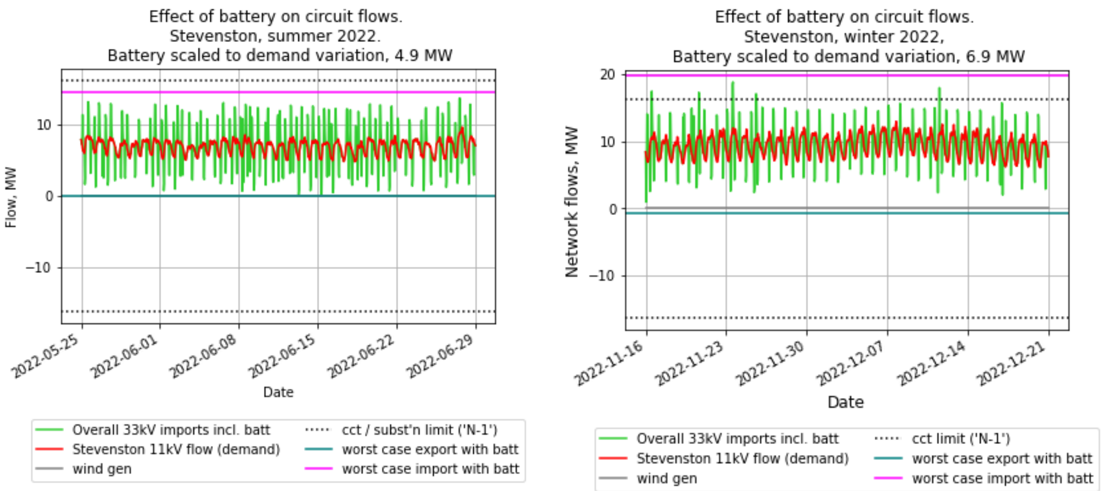
Sizing a battery to the level of demand might be thought of as a plausible approach to reducing circuit flows, but Figure 71 shows that at demand-only location Stevenston, this size of battery is far too large to potentially have such an effect.



(a) Stevenston, Summer (c) Stevenston, Winter

Figure 71 Effect of a battery, sized to maximum demand, on overall network flows. Stevenston, summer and winter

Sizing the battery to *variations in demand* that occurred during the case study period yields an improvement, but even these significantly exceed the general diurnal variations in demand power flows, as demand flows varied a little from day to day during the study period, as illustrated in Figure 72.



(a) Stevenston, Summer (b) Stevenston, Winter

Figure 72 Effect of a battery, sized to demand-variation within the case-study time period, on overall network flows. Stevenston, summer and winter

6.6.2. Batteries of other durations and round-trip efficiencies

Batteries of 2-hr, 4-hr and 12-hr durations were simulated, with round trip efficiencies of 85% (all durations) and 70% efficiency (2-hr and 12-hr batteries only).

The resultant simulated circuit flows, for Largs and Stevenston, in all seasons, are shown in Chapter 6 Annex 13. These are discussed in the following section.

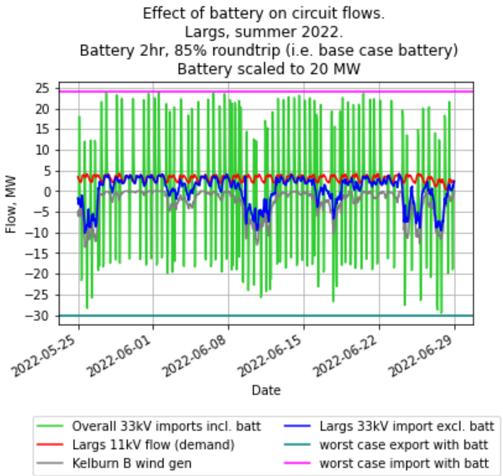
Only a single scenario, the one which allowed the battery to accrue the highest revenue, is modelled here. For the 12-hour batteries in particular, several scenarios result in similar revenues. The highest-earning one is displayed, but there exist alternative similarly rational behaviours.

As shown in Chapter 4, the "best cashflow" scenarios for 4-hour batteries have generally similar patterns of behaviour to those of 2-hour batteries, so similar effects on network flows are seen. 12-hour batteries, however, have more irregular trades, and batteries of lower round-trip efficiencies (70%) trade less often, especially in summer.

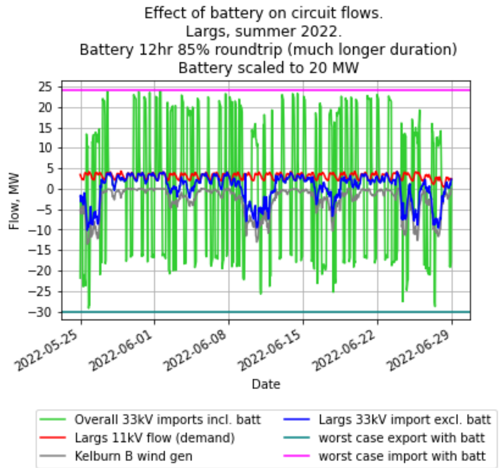
6.6.2.1. Effect of increasing the battery duration

Increasing duration of the battery from 2 hours to 4 hours produced a broadly similar timeseries of battery actions, as discussed in Chapter 4 (Section 4.8, full results tabulated in Chapter 4 Annex 3). The effect of such batteries on network flows is shown in Chapter 6 Annex 13, together with batteries of 2-hour and 12-hour duration.

Figure 73 shows the difference in projected overall network flows, in the case of a 2-hour battery (left hand side chart) and a 12-hour battery (right hand side chart), both of the same round trip efficiency. The 2-hour battery (left hand side) is projected to have imports and exports every day, usually of 2 hours, often around twice a day. The 12-hour battery (right hand side) has some days of no activity and generally less regular activity; however the major difference between these two batteries is that the 12-hour battery sometimes engages in prolonged (~ 12-hour) imports or exports. Near-12-hour imports occurred during the high wind event in the middle of the case study period, and also the final high wind event of the case study, which in this case, fitted well with network flows, unlike the 2-hour battery, which engaged in both imports and exports during these events. However, over the case study, there was little difference between the magnitudes and occurrences of the largest network import and export flows, between the two batteries.



2-hour battery (85% round-trip)



12-hour battery (85% round-trip)

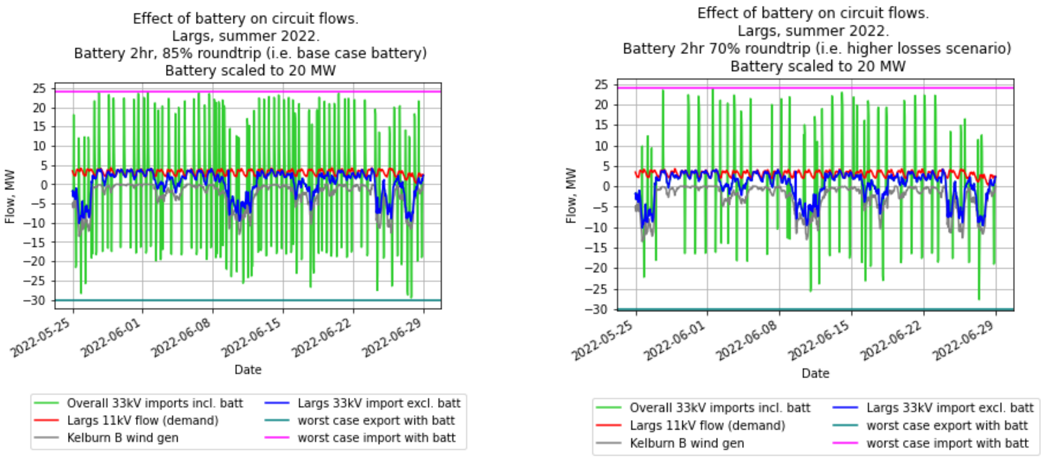
Figure 73 Effect of increasing battery duration from 2 hrs to 12 hrs (85% round trip). Largs, summer

6.6.2.2. Effect of reducing the battery round-trip efficiency

As stated in Chapter 4, the battery simulation model has a rule encoded which instructs the battery not to engage in a trade if the likely revenue from that trade would be insufficient to cover the cost of round-trip losses arising from that trade. Thus, when increasing the round-trip losses in the battery simulation model, aside from reducing accrued revenue, an increasing number of trades are disallowed. It is therefore not surprising that the modelled battery activity is reduced.

2-hour battery (Figure 74)

In the summer case study, the base case battery (85% round-trip, left hand side chart) has exports and imports often around twice a day, but in contrast, the more "lossy" battery (70% round-trip, right hand side chart) is far less active, having imports and exports often only once every few days. This greatly reduced pattern of activity, for the more "lossy" battery, also reduces the number of occasions on which the battery flows exacerbate overall network imports and exports to approach "worst case" network flows, compared to the base case battery. In this case, the more "lossy" battery caused a slightly lower magnitude of "worst case overall export flow", compared to the base case battery, but both batteries had the same magnitude of "worst case import flow", during this case study period.



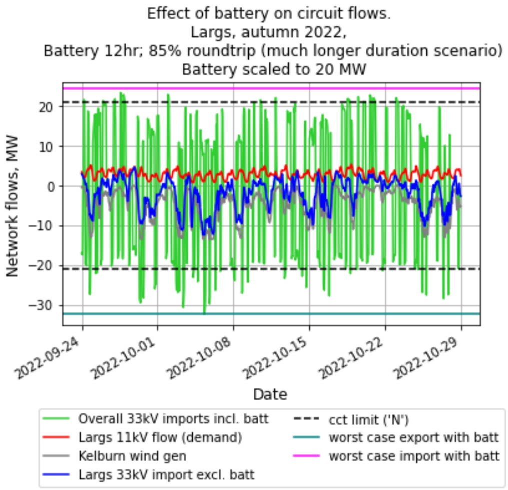
2-hr, 85% round-trip 2-hr, 70% round-trip

Figure 74 Effect of reducing the round trip efficiency of a 2-hr battery from 85% to 70%. Largs, summer.

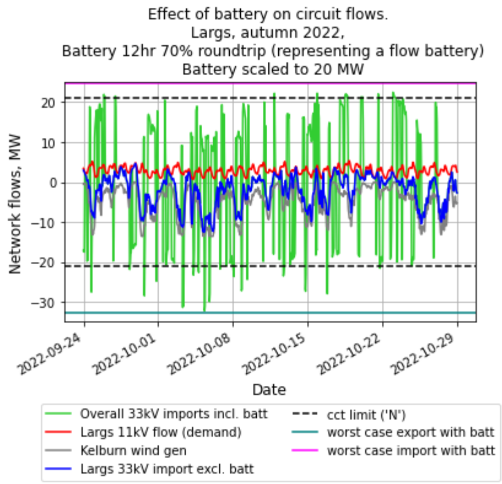
Similar though less pronounced differences in activity, between 85% and 70% round trip 2-hour batteries, were seen in the other case study seasons, as tabulated in Chapter 6 Annex 13.

12-hour battery (Figure 75)

For 12-hour batteries, there is also a marked reduction in the frequency of imports and exports between a battery of higher efficiency (85% round-trip, as shown in the left hand chart) and the more lossy battery (70% round-trip, right hand chart), here using the autumn case study as an example. Whereas the higher efficiency battery was active on most days, the more lossy battery had several days of no activity (e.g. in the middle of the first week, and the last few days, of the case study). Unlike the higher efficiency round-trip battery, the more lossy one does not export during the last two high wind events of the case study (behaviour which contributes to high overall export flows) but both batteries export during several high wind events earlier in the case study, and the highest magnitude overall network export flow during this case study season was the same for both batteries. Both batteries had similar effect on the highest overall import flows of the network, during this case study.



12-hr, 85% round-trip



12-hr, 70% round-trip

Figure 75 Effect of reducing the round trip efficiency of a 12-hr battery from 85% to 70%. Largs, autumn

Taken together, these results display the difficulty in trying to predict what effect battery activity might have on network flows, given the diversity of possible profit-making actions.

It also shows that longer-duration batteries, if connected, are likely to behave differently to batteries of shorter duration, with less regular patterns of actions.

6.7. Discussion

This chapter addresses, in part, the following research questions:

What kinds of behaviours are foreseeable from short-duration batteries?

Would these behaviours be likely to

- *alleviate or exacerbate network congestion and / or system needs?*
- *Reduce or increase overall costs?*
- *Facilitate or obstruct renewable deployment and transition to Net Zero?*

This section also considers the hypothesis:

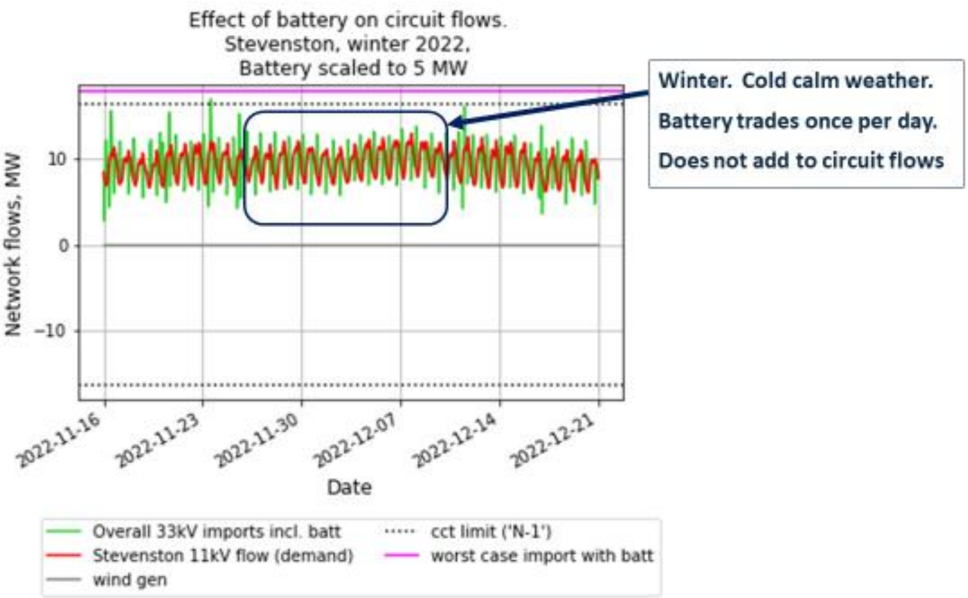
"*Battery actions will not add to distribution network congestion*", as stated in Section 6.1.

Examples of differing behaviour, with respect to the hypothesis, are given in Section 6.7.1 and Section 6.7.2 below. The later subsections consider the effects of battery sizing (MW), type of location, and of other battery parameters.

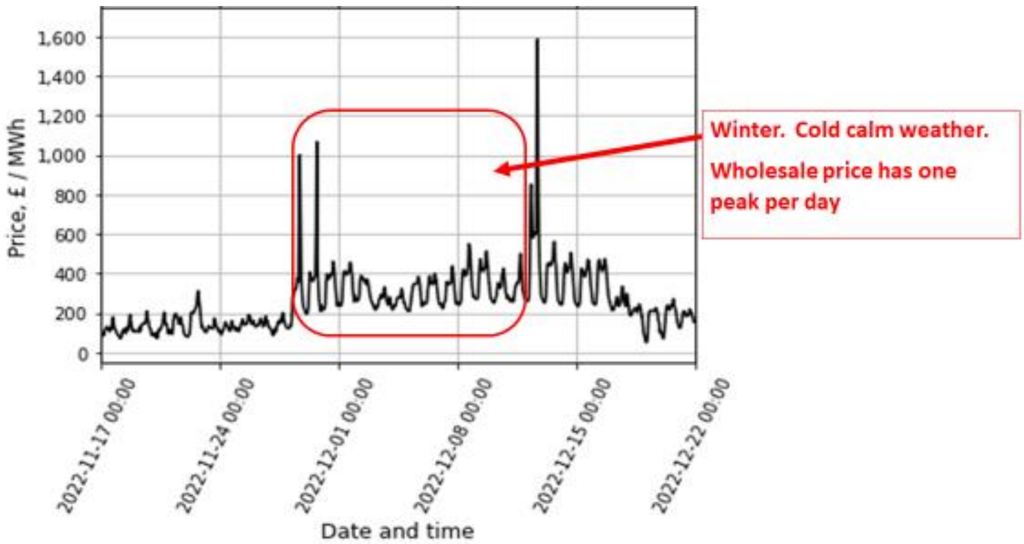
6.7.1. Examples of battery trades relieving, or not adding to network flows

As discussed in Chapter 4, and illustrated in Figure 76, the price pattern during the cold low-wind period in the winter case study was predominantly “one peak a day”, encouraging battery imports at night, when price was low, and exports during early evening, when price reached a maximum.

Here, the pattern of wholesale price aligns beautifully with that of network flows, incentivising the battery to act to reduce, or at least not add, to network flows.



(a) Stevenston network flows and battery actions. Winter case study. Battery 5 MW, 2 hours



(b) Wholesale electricity price timeseries (Nordpool, Day Ahead). Winter case study.

Figure 76 Network flows with a 5 MW 2-hour battery at Stevenston, and wholesale price pattern, winter case study

This is an example of battery action concurring with the hypothesis: "*battery actions will not exacerbate maximum network flows nor add to network congestion*".

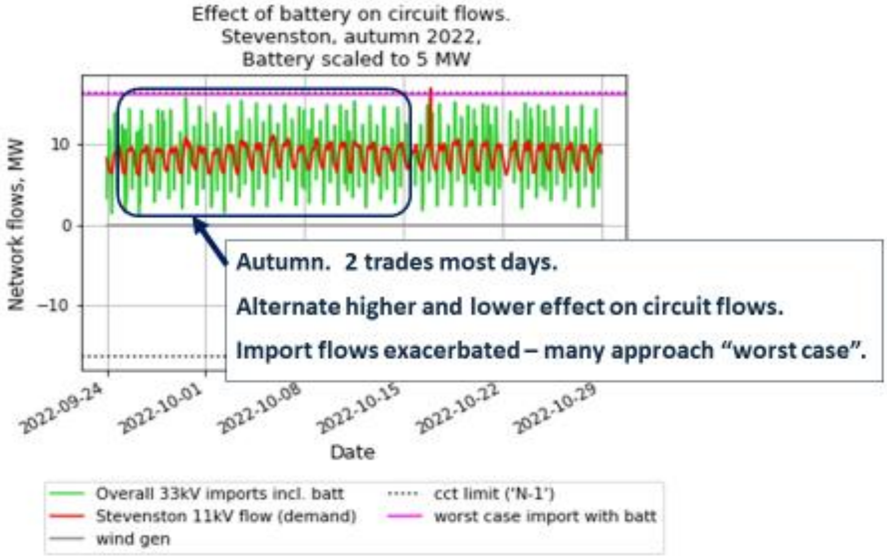
However, this situation is not found at some other times; examples are described below.

6.7.2. Examples of battery trades exacerbating network flows

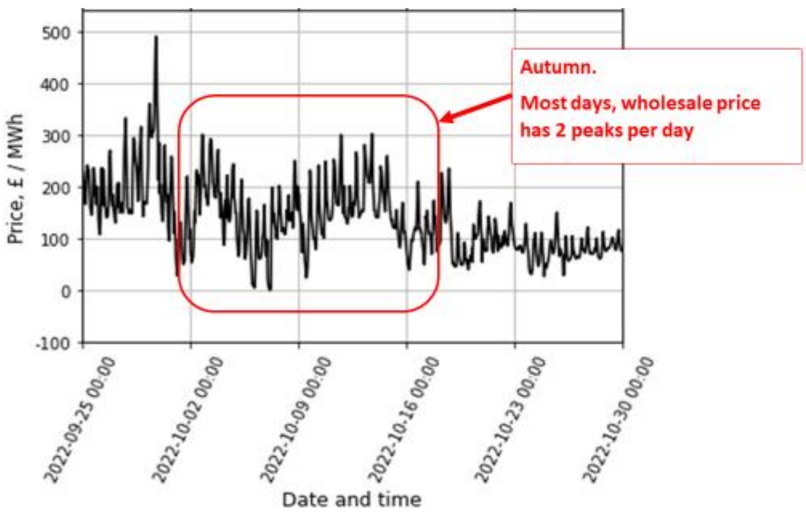
6.7.2.1. Demand-only site

As in the case above, the wholesale price pattern in autumn encourages the battery to import during the night, and to export in early evening most days, trades which fit fairly well with Stevenston's pattern of demand flows.

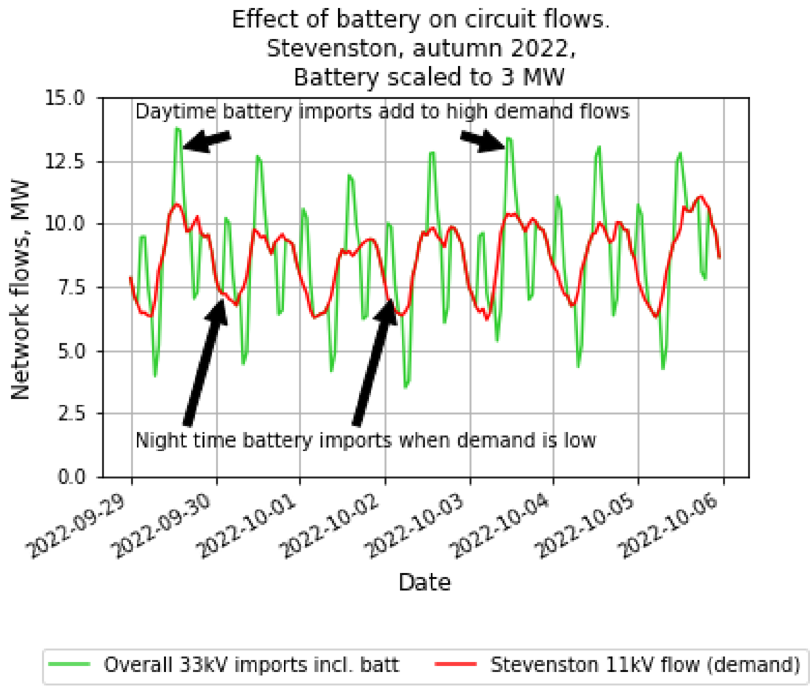
However, as Figure 77 shows, the autumn price pattern has a "2-peak per day" pattern on most days, encouraging an additional export in the morning, and an additional import around midday. These additional daily trades fit poorly with Stevenston's "one peak per day" demand profile, and exacerbate maximum import flows; a slightly larger sized battery would also cause net export flows in the morning, as they often occurred at a time of day prior to the main daily demand rise at this location.



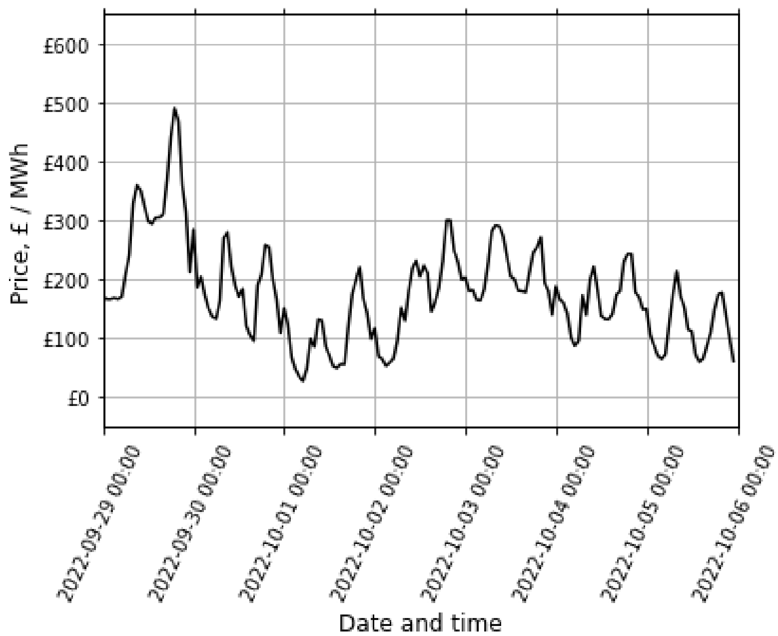
(a) Stevenston network flows and battery actions. Autumn case study. Battery 5 MW, 2 hours



(b) Wholesale electricity price timeseries (Nordpool, Day Ahead). Autumn case study.



(c) 1-week excerpt: effect of 2-hr battery on Stevenston's circuit flows, 29 Sept-6 Oct 2022



(d) 1-week excerpt: wholesale electricity price 29 Sept-6 Oct 2022

Figure 77 Network flows with a 5 MW 2-hour battery at Stevenston, and wholesale price pattern. Autumn case study

6.7.2.2. *Generation-dominated site*

Figure 78 illustrates a different case, one where exports from a windfarm dominate network flows. The grey line, depicting windfarm exports, runs only slightly below the blue “overall network flows from wind and demands” line, because the demands (red line) at this location are small.

As discussed previously in Chapter 5, battery actions, both imports and exports, continue in conditions of both high and low wind, and their exports at windy times serve to add to overall network flows. In the example below, Lochan Moor has minimal room for additional export flows, and even a modestly-sized 5 MW battery would exceed the network limit.

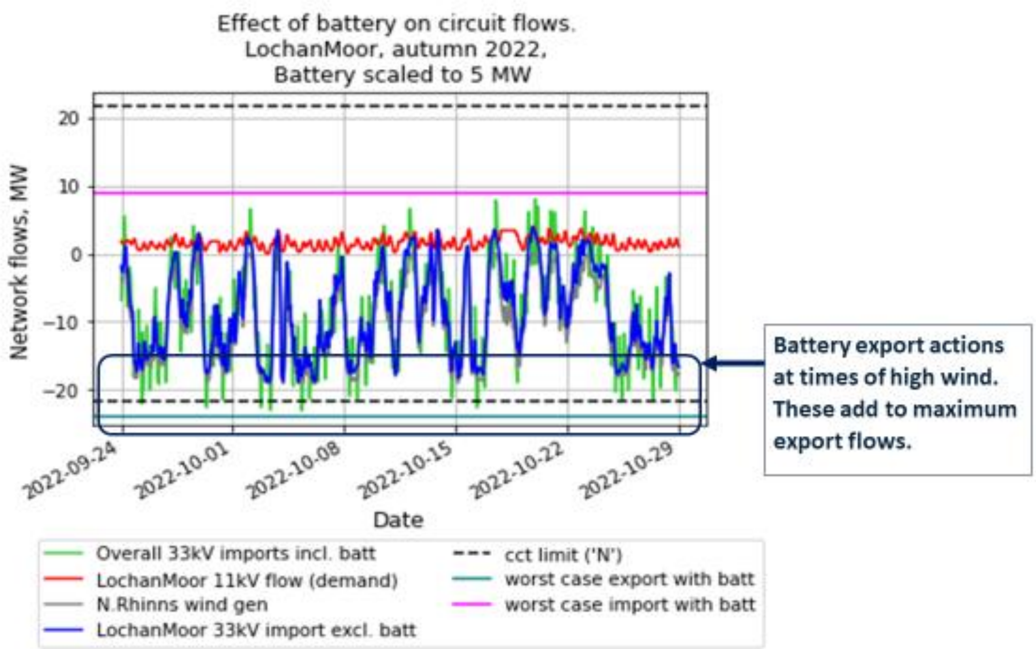


Figure 78 Effect of a 5 MW 2-hour battery on network flows at generation-dominated Lochan Moor. Autumn case study.

6.7.3. Seeking an appropriate size (MW capacity) for batteries

As described in Section 6.6.1.2, batteries were sized against circuit- and season-specific parameters of maximum generation, maximum demand, and variation in demand across the season.

In all cases, such batteries would considerably add to maximum import, and in most cases, export flows, for two reasons:

- For demand-dominated flows, the in-day variation in flows was much smaller than the maximum generation, maximum demand, or even the in-season demand variation
- More fundamentally, at least some of the time in all seasons, the battery actions did not align well with network needs, and would exacerbate both import and export flows. There is no ideal size – other than zero MW - for a battery behaving in such a way.

6.7.4. Different durations and round-trip efficiencies of battery

For networks where wind patterns dominate flows, such export events typically last for many hours, sometimes for more than a day. In such locations, short-duration batteries could have limited effectiveness in relieving network export flows lasting for much longer than the battery's duration, even if their actions were well-timed with wind flows[72]. It might be expected that batteries of much longer duration would be better suited to such locations.

As discussed in Chapter 4, and stated in Section 6.6.2.1 of this chapter, patterns of network flows are fairly similar for batteries of durations 1 – 4 hours, i.e. there is little obvious benefit to the network of having batteries which can charge up for 4 hours, as opposed to 2 hours.

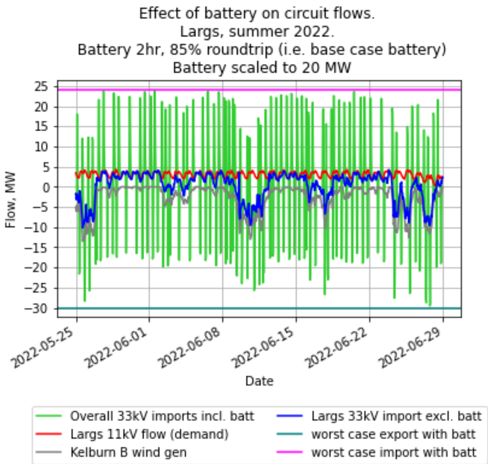
However, significantly different patterns are seen in simulated 12 hour batteries, as previously discussed in Chapter 4, and in Section 6.6.2 of this chapter, with further results shown in Annex 13.

Two sites, moderately and strongly wind-dominated Largs and Lochan Moor, respectively, during the are viewed, with a battery of 20 MW capacity.

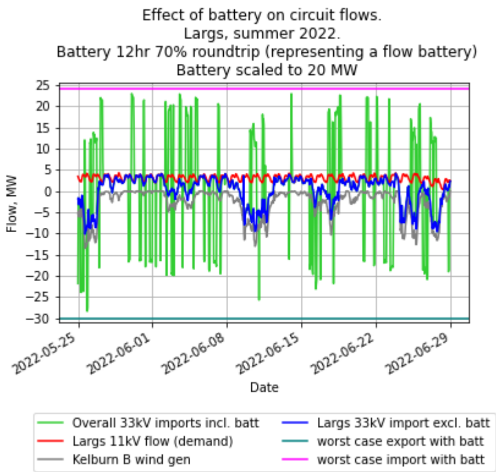
Figure 79 compares the actions of a simulated 2-hour lithium battery, and a 12-hour flow battery (of 70% round trip efficiency) during the summer case study. This shows that, though in all cases the battery at times adds significantly to maximum export flows, the simulated flow battery does so far less often, and of lower magnitude, compared to the 2-hour battery.

[72] A battery could be oversized, and operate for longer durations at reduced power. However, such operation may be less financially viable for the battery owner than expecting to utilise the battery at its rated capacity.

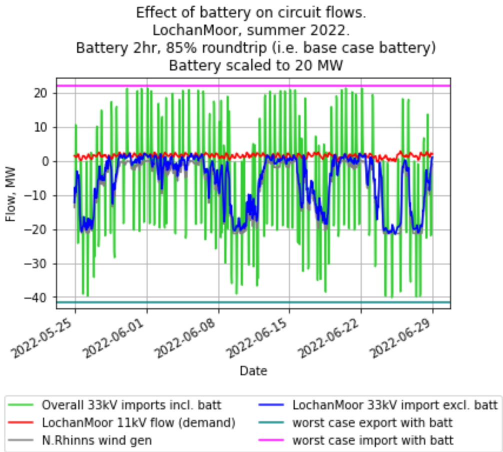
Furthermore, the flow battery imported for much of several a high wind events, actions which would relieve network congestion, though the flow batteries did also briefly export during these events.



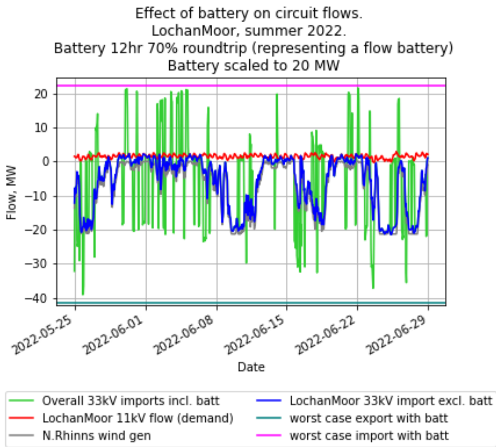
(a) Largs, 2-hr 85% round-trip, base case battery



(b) Largs, 12-hr, 70% round-trip "flow battery"



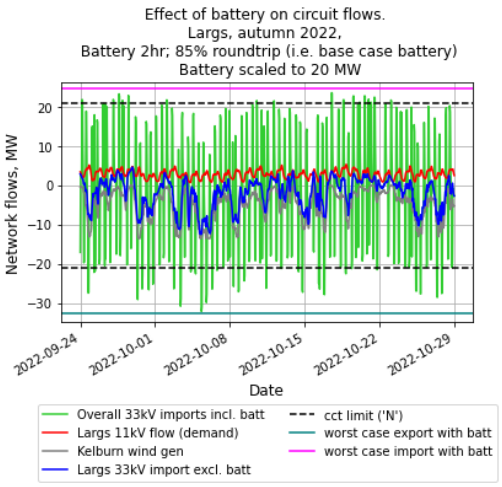
(c) Lochan Moor, 2-hr 85% round-trip base case battery



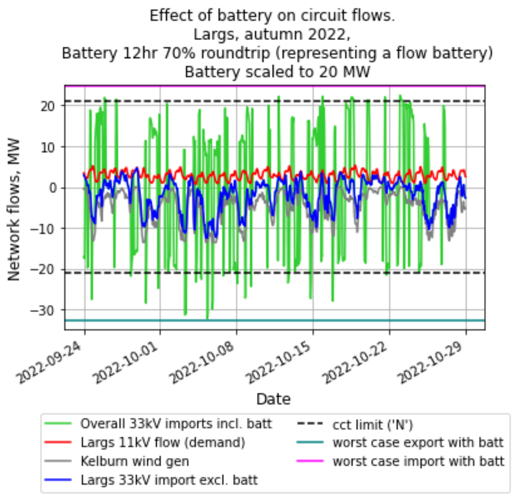
(d) Lochan Moor, 12-hr, 70% round-trip "flow battery"

Figure 79 Comparing simulated lithium 2 hour and 12-hour flow battery actions on network flows at Largs (a, b) and Lochan Moor (c, d) SUMMER case study

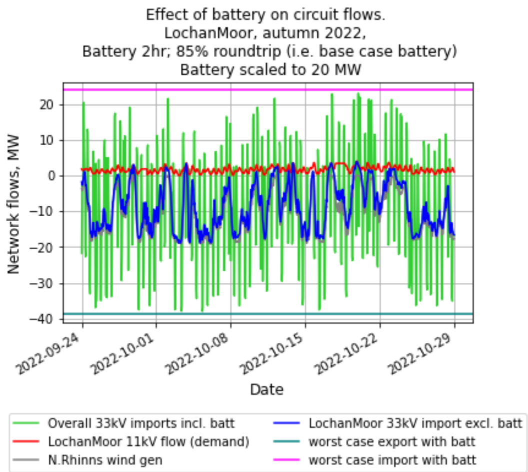
Broadly similar results are seen in the autumn case study period, as shown in Figure 80.



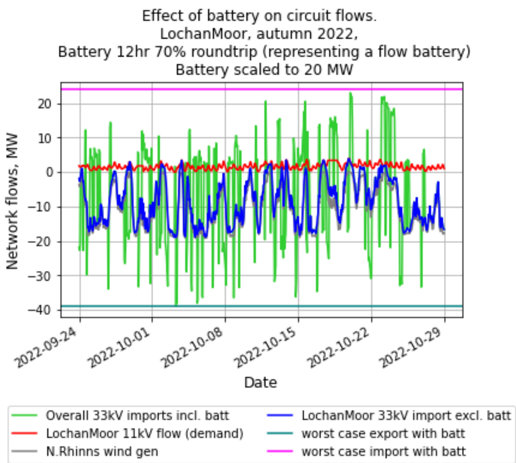
(a) Largs, 2-hr 85% round-trip base case battery



(b) Largs, 12-hr 70% round-trip "flow battery"



(d) Lochan Moor, 2-hr 85% round-trip base case battery



(e) Lochan Moor, 12-hr 70% round-trip "flow battery"

Figure 80 Comparing simulated lithium 2 hour and 12-hour flow battery actions on network flows at Largs (a, b) and Lochan Moor (c, d), AUTUMN case study

These plots show that actions of storage assets of a longer duration (e.g. 12 hours) are arguably a better complement than 2-hour batteries, for networks with maximum power flows dominated by high-wind events, because such wind events often last from around half a day to several days. This is especially the case for the longer-duration storage having a lower round-trip efficiency, which serves to reduce the numbers of trade, and, in the simulations used here, to favour a longer-term view of forthcoming prices. However, longer duration assets would still continue to cause some occasions of exacerbated and potentially "worst case" network export and import flows, though less frequently than for short-duration batteries.

Inspection of different types of batteries at demand-only Stevenston found different results. There was little advantage of the longer-duration battery compared to the 2-hour battery, regarding the magnitude of import flows, during the summer case study period, as shown in Figure 81 with similar results for the autumn case study periods, shown in Chapter 6 Annex 13.

(a) Stevenston, 2-hr 85% round-trip base case battery

(b)Stevenston, 12-hr 70% round-trip "flow battery"

Figure 81 Comparing simulated lithium 2 hour and 12-hour flow battery actions on network flows at Stevenston, (charts a, b, respectively) in SUMMER.

These analyses show that actions of batteries could vary significantly according to their duration and round-trip efficiency, as well as, it is surmised, the chosen approach of the operator. While a battery, engaged in wholesale trades, would be expected to export at times of high price and import at times of low price, a network operator could have difficulty in predicting when and how often such a battery might act.

For network flows on wind-dominated sites, longer duration (12-hour) batteries, especially batteries with parameters representing a flow battery, appear to have actions that would better utilise spare network capacity, than short-duration (2 hour or 4 hour) batteries. However even in these cases, such batteries would at times exacerbate the highest export and potentially highest import flows.

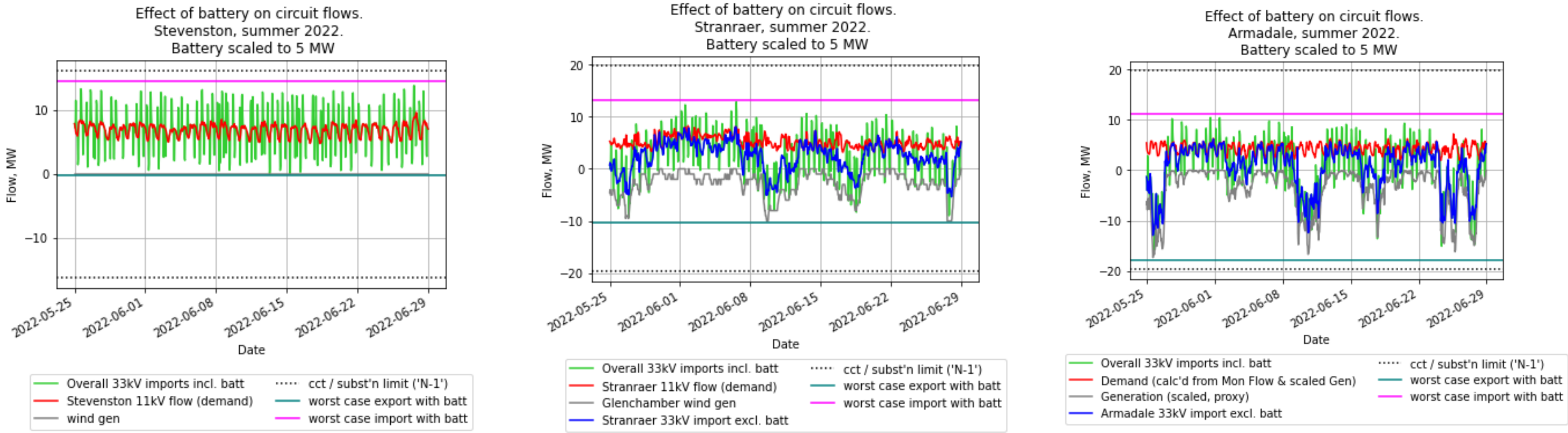
6.7.5. What characteristics of a location might make it suitable to have a battery connected?

This section discusses whether a battery might be better accommodated at a site at which network flows are strongly generation-dominated, strongly demand-dominated, or have a mixture of both types of flow. It might be supposed that the actions of a battery might fit well with a site which is either pure demand, or pure generation.

However, examination of network flows at Stevenston found that a battery, in summer and autumn, would exacerbate import flows on a daily basis. This is not the case for other locations, namely Armadale, Largs and Stranraer, where wind generation often reduces or eliminates import flows, so such occasions occur less often, as shown in Figure 82.

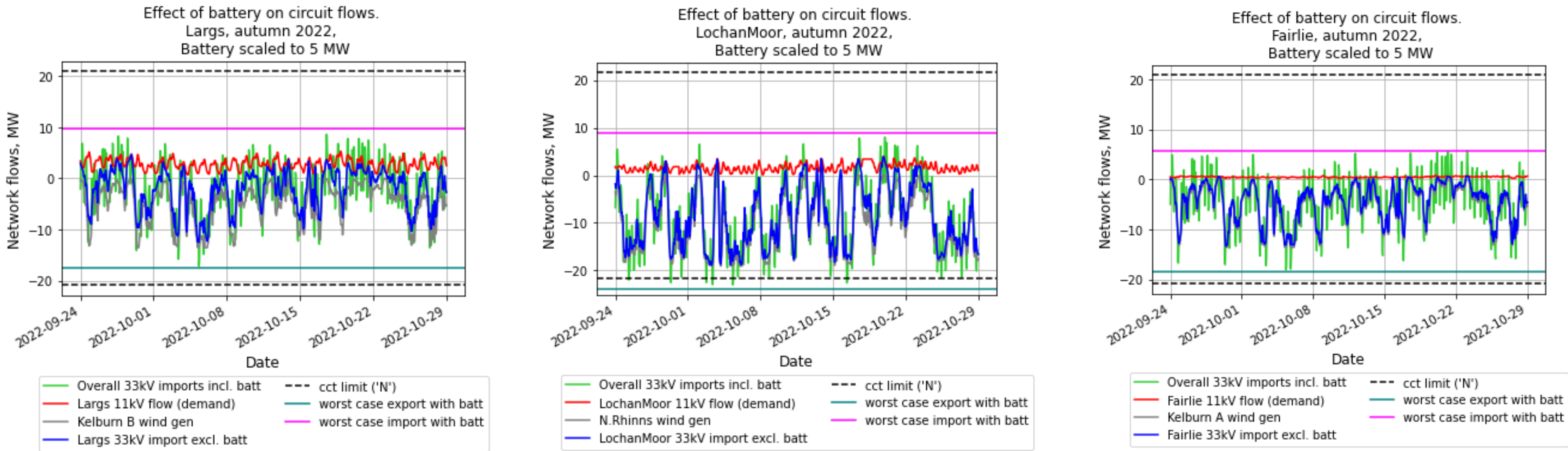
Similarly, Fairlie and Lochan Moor have very little demand, and a battery would exacerbate the exports during most wind events, effects which are reduced by the demands of sites with towns, with Largs illustrated for comparison in Figure 83.

Considering that batteries have to be considered a “problem” for networks, as well as a possible “solution”, in considering where they could be better accommodated, sites with a mix of demand and generation have fewer occasions of maximum flows, in either direction, compared to demand-only or generation-only site. Thus sites with both demand and generation connected appear better able to tolerate battery activity, with fewer occasions of overall maximum network flows.



(a) Stevenston (b) Stranraer (c) Armadale

Figure 82 Comparison of effect of 2-hour 5 MW battery on maximum import flows at Stevenston, Stranraer and Armadale. Summer case study



(a) Largs (b) Lochan Moor (c) Fairlie

Figure 83 Comparison of effect of 2-hour 5 MW battery on maximum export flows at Largs, Lochan Moor and Fairlie. Autumn case study

6.8. Conclusions

This work addresses the following research questions:

> *What kinds of behaviours are foreseeable from short-duration batteries?*
>
> *Would these behaviours be lively to alleviate or exacerbate network congestion and / or system needs?*

And investigates the hypothesis:

> *"Deployment of suitably -sized distribution-connected batteries, engaged in wholesale electricity trades, will not increase congestion on distribution networks servicing residential load demand and windfarms."*

Batteries engaged in arbitrage with pricing patterns as seen in the 2022 study periods are likely to increase network exports in areas with wind generation. Batteries are also likely to increase network imports in import-dominated network areas, and in all areas at times of low wind. The hypothesis, that deployment of batteries will not increase network congestion, has been disproven.

There are occasions when a suitably-sized battery engaged in arbitrage would reduce network congestion, or at least not increase it to a significant extent. However, these occurrences were relatively unusual. Overall maximum imports and exports can approach, and in some cases, reach, the "worst case" conditions of batteries exacerbating maximum network flows, for both imports and exports. It is therefore appropriate for network owners to offer connections with such an expectation, in the absence of any other measures to limit flows.

Sizing a battery to maximum generation flows, or maximum demand flows, would significantly increase network flows. Sizing a battery to average in-day variation in demand would be appropriate for demand-dominated sites, at times when battery actions fit well with demand patterns, but at other times even the "best case" sizing would cause increased network flows.

Battery actions may vary considerably according to battery duration and round-trip efficiency, as well as the chosen approach of its operator, parameters and choices which may change with time as battery and associated equipment ages. A network operator could thus have difficulty in predicting how often a battery would import and export. If a network operator did have foresight of battery actions, it could potentially assess the battery's interactions with other network users, and the extent to which the battery might reduce or exacerbate overall network flows, foresight which could help the network owner with decisions about connection requests, network expansion and other potential actions to address capacity constraints. A brief inspection of likely actions of 12-hour batteries, with parameters intended to represent a flow battery, suggests such a battery's actions would fit better with network flows on wind-dominated sites than actions of short duration batteries, though even in such cases, it is likely that there would still be occasions of batteries exacerbating worst-case network export flows, and potentially also import flows.

Network locations with a mixture of both demand and generation flows appear better placed to tolerate additional flows from batteries, compared to networks whose flows are entirely or mainly either demand or generation.

Further work is recommended to investigate whether similar results are found on networks with other types of generation, especially solar PV. Investigation of battery actions with projected future prices of a renewables-dominated power system would be topical and may yield different results.

The following chapter explores scenarios in which oversized batteries are installed at the above locations, and connected with *non-firm connections*.

7. Chapter 7 Projected curtailment costs for distribution-connected batteries with non-firm connections

Chapter summary

This chapter builds on chapter 6, which examines the effect of a battery, engaged in wholesale trades, on distribution network congestion, using 6 case study locations and 3 cases study time intervals in 2022.

This chapter examines scenarios in which batteries would connect under a *flexible connection*, which would allow them to trade up to the available network capacity at the time. Though little used to date for storage assets, the principle of offering renewable generators "flexible" as opposed to "firm" connections, in areas of network constraint, is well-established. This chapter investigates the feasibility of applying such an approach to batteries.

Batteries of durations 2-hour and 4-hours are simulated, acting according to their "highest cashflow" scenarios, as described in chapter 4, but with their flows limited at times by network constraints. The battery's forgone overall net revenues, termed "*curtailment costs*" are enumerated for a range of battery sizes, up to 40 MW in excess of estimated network spare capacity (termed "network headroom"), taking into account the tightest network limits and maximum projected overall demand and generation flows. For the three locations connected to GSP with two feeders, curtailment costs under abnormal ("N-1") conditions are also enumerated, for the same battery sizes, using "high", "medium" and "low" failure rate scenarios.

This work found that connecting batteries with a flexible connection is an eminently feasible approach, and a likely "win-win" at appropriately sized batteries. Batteries could be sized up to around 10 – 20 MW in excess of the "network headroom", and yet generally suffer relatively little cost of curtailment: up to around 5% of the average overall net revenues they would accrue if unconstrained. Curtailment costs in most cases were lower for batteries located on networks with a mixture of wind generation and demand, rather than at locations strongly dominated by one flow type only. However, one location showed the importance of site-specific factors in curtailment costs.

Considering certain scenarios of abnormal operating conditions is especially important in the light of ENA guidance [102] regarding firmness of connection for new storage assets. The work in this chapter found that curtailment costs could be significant for "medium" and "high" failure rate scenarios, especially for locations with long feeders, reaching up to 5% of unconstrained overall net revenues, though much lower for locations with shorter feeders. At all three case study locations which have two feeders, costs under conditions of a network outage were also found to be significant, compared to curtailment costs under intact network conditions, for batteries sized up to 10 – 20 MW in excess of network headroom. At larger battery sizes, curtailment costs under normal (intact) conditions are far larger. The battery curtailment costs under network failure conditions are based on long term average durations of network outages; more detailed analysis using probabilistic modelling is recommended.

7.1. Aims and introduction

This work continues from Chapter 6, which examined potential effect of a grid-scale battery, engaged in arbitrage, on maximum network flows at selected sites on a distribution network.

This chapter investigates the behaviour of a battery connected with a *flexible connection*, i.e. under which the battery activity would be curtailed, whenever necessary, to keep power flows within network limits. It is also necessary to evaluate the impact of battery curtailment on the battery's revenues, to understand whether such an arrangement may be commercially viable.

This work seeks to identify scenarios in which costs of curtailment are smaller or greater, to decide which scenarios might or might not be credible. Results of this work are used in this and the following chapter to consider whether, and in what circumstances, connecting a battery with a flexible connection might be a lowest cost solution.

7.2. Definitions and Background

7.2.1. Definitions

A "firm connection" grants network users the right to import and / or export up to the agreed connection limit, at any time; a "flexible connection" (also called a "non-firm connection") allows the user to import and / or export, but with restrictions.

In situations where there is plenty of capacity on the network under all relevant circumstances, a DNO would normally grant a "firm connection" to a new developer, in this case, a battery project. However, if there is insufficient network capacity to accommodate the additional power flows from the developer, at all times, while satisfying all applicable codes and standards [77], [237], the DNO cannot offer a firm connection to the network in its current state.

In such a situation there are two ways in which the project can proceed. The "traditional approach" (elaborated in the following section) is for the DNO to perform reinforcement work, to increase the capacity of the network, then grant the connectee a firm connection. The developer which triggers this reinforcement work would normally be liable to pay towards this work [237], as is discussed in the following chapter.

The other option is for the developer to connect with a "flexible connection", under which the developer accepts some restrictions to its activities. Arrangements may be bespoke or apply to multiple network users. Restrictions may relate to timing, capacity of imports and exports, and / or to normal or abnormal system operating conditions. Network users are not compensated for any curtailment. Thus, users may opt to connect with a flexible, rather than a firm, connection, in order to be granted a cheaper and often faster connection to the network, though they bear the risk of forgone revenue when network access is restricted [238], [239].

This section investigates the scenario in which batteries are connected with a flexible connection, of a type which monitors network flows in real time, and allows the batteries to import and export *up to the available network capacity at that time,* taking into account the flows from demand centres and generators. This may be possible with a *Local Management Scheme* for a single battery; for more complex situations an *Active Network Management (ANM)* system may be necessary [238], [239].

7.2.2. Flexible connections - historical background in Great Britain

Unlike the GB transmission system, which has traditionally had an Electricity System Operator monitor power flows and control levels of generation, distribution networks have traditionally operated passively. New connections were allowed when their power flows, combined with those of existing users, would not breach network limits, under even "worst case" conditions: reinforcement prior to connection was performed if necessary. Hence, little monitoring of distribution network power flows was required: the approach was sometimes called "*fit and forget*". However, the advent and roll out of variable renewable distributed generation precipitated a need for "active management" of power flows on these previously-passive distribution networks [240]–[242]. ([243] notes that an EV roll-out is now also provoking a similar effect in other areas of distribution grids in Europe.)

In 2009, the first trial of "active network management (ANM)" on a GB distribution network, in a network area with multiple connected renewable generators, was run on Orkney, a small archipelago of islands to the north of Scotland, which has significant wind energy resource, but limited capacity of electrical connections [244], [245]. In this trial, windfarms could connect with *non-firm* connections, and avoid some of the network reinforcement work that would be necessary for full export under all network conditions. These arrangements enabled lower-cost connections, often in a shorter time, as they avoided some of the time and capital expenditure associated with a preparing the network for new firm connections. However, a condition of the *non-firm* access was that the windfarms' output would be curtailed, without compensation, at times of network constraint [246]. By 2018, all the six GB DNOs were able to consider at least one type of flexible connection, and most DNOs were offering several types of flexible connection, as standard offerings [239].

In Ofgem's 2022 decision on a Significant Code Review of Access Charges [to electrical networks] [247], Ofgem noted the use of flexible connections to enable cheaper and quicker new connections in areas of constraint. This review concluded that non-firm access arrangements will continue to be available in areas where network reinforcement would otherwise be needed, but set out some improvements to arrangements for granting of non-firm connections. Going forward, DNOs will be required to set and abide by maximum curtailment limits to the connecting customer, and that non-firm connections will have specific end-dates (subject to some exceptions). The latter ruling shows a view of non-firm connections generally being an interim rather than a permanent solution to network congestion, and that DNOs are expected, in time, to reinforce the network, where necessary.

For context, the overall capacities of connections with a "flexible" and "firm" connections in SPEN's Scottish Distribution area, as of November 2023, are tabulated in Table 36. Very significant capacity of flexible network connections has been agreed, amounting to over 3 GW of aggregate capacity. Thus, this is a scenario worth investigating.

Table 36 Capacity of firm and flexible connections for generators and storage assets. SPEN's Scottish Distribution Network, Nov 23 [228]

	Firm connection	**Flexible connection**	**Connection type not stated**	**Total**
Total capacity: "Connected" (MW)	2366	186	110	2662
Total capacity: "Accepted to connect" (MW)	2296	3086	2674	8057

7.2.3. Current recommendation on "firm" connections for storage customers

In 2023, the UK electricity networks trade body, the Energy Networks Association (ENA), proposed, and gained support from Ofgem, for a "tactical solution" for DNOs regarding granting of new connections to storage assets, together with two other tactical solutions on other aspects of accommodating increased volumes of storage on their networks [102]. These tactical solutions were proposed in the context of 53 GW of connections agreements for electricity storage assets on distribution networks across GB. Such a huge volume of storage connection agreements has much reduced spare network capacity, in some cases to zero, in some areas. This situation reduces DNOs' ability to accommodate further increases in both generation and demand that will be necessary to meet Net Zero goals, a situation the ENA regards as detrimental to both customers and energy transition.

The ENA considers that the standard "minimum scheme" offering a DNO would make would often grant storage customers *too high* a level of firmness of access: a level *"that was originally developed and economically justified for groups of customers (e.g. whole towns), for whom the value of supply security is much greater than for electricity storage customers."* The ENA's expresses its concern that continuing to grant what the ENA considers to be "inappropriately high [level of] network access rights to some electricity storage customers" risks causing adverse impacts on GB customers. The ENA believes that the "very high level of firmness" currently awarded to storage customers tends to be used infrequently, and this network capacity may be of greater benefit to other customers. . The ENA is also concerned that storage-related network reinforcement may "divert valuable DNO resource" away from "delivering the interventions customers need to enable Net Zero", and that a portion of reinforcement costs would be socialised across all customers' bills.

The ENA recommends that all DNOs should grant storage customers, whose connection applications are received on or after 30 September 2023, a lower level of firmness than other customers. The ENA's recommendation is as follows:

> *"The Minimum Scheme*[73] *shall be determined on the basis that the import to and export from the electricity storage customer's premises:*
> *1. [the storage customer] should not ordinarily be curtailed or interrupted when the relevant parts of the distribution network are intact; but*
> *2. [the storage customer] may be curtailed or interrupted when any of the relevant parts of distribution network are not intact (including but not limited to First Circuit Outages and Second Circuit Outages).*

[73] "Minimum scheme" is the network arrangement, with reinforcement if necessary, required to accommodate a new connection at minimum cost. It is the standard offering a DNO would give a new customer requesting a connection. Types of connection are discussed further in Chapter 11.

The electricity storage customer's connection offer and connection agreement shall include terms which explicitly permit unlimited, uncompensated curtailment / interruption when the relevant parts of the distribution network are not intact… The DNO should use reasonable endeavours to minimise the amount of curtailment / interruption, even where it is permitted by the connection agreement."

This recommendation applies to assets which are "wholly or mainly electrical storage", and would not apply to most domestic customers, nor commercial / industrial customers with demands similar to residential demands, nor unmetered customers. The recommendation does not affect a storage customer's ability to opt for a "flexible connection", in which access may be curtailed at times when the network is intact but experiencing congestion.

Regarding network planning for abnormal operating conditions ("N-1", "N-2"), the ENA's Tactical Solution 2 [102] offers guidance on interpretation of EREC P2/8 requirements on networks where electricity storage is connected. With an aim of avoiding unnecessary network reinforcement, the guidance instructs DNOs to consider controllable electricity storage assets as having Demand Side Response, thus storage imports potentially need not be secured during outage events, depending on firmness of contract and type of outage. For uncontrollable storage, the guidance instructs DNOs to use relevant diversity factors for storage assets when considering the level of Group Demand that needs to be secured during outage events.

Given the scale of storage applications, and the challenge of meeting energy transition goals, further developments in rules and guidance are likely.

7.3. Methodology

This section is set out as follows.

Subsection 7.3.1 gives a high-level description of the approach taken.

Subsection 7.3.2 describes the approach used to select the sizes (MW capacities) of batteries for each case study location, and to calculate annual revenues and costs.

Subsection 7.3.3 considers the three 2-feeder locations, under abnormal circuit conditions of one feeder or transformer being unavailable.

7.3.1. Approach overview

A summary of the whole methodology used to enumerate curtailment costs for batteries, of different sizes, at the different locations, is presented in Figure 84.

Description of individual calculation stages follows in later parts of Section 7.3.

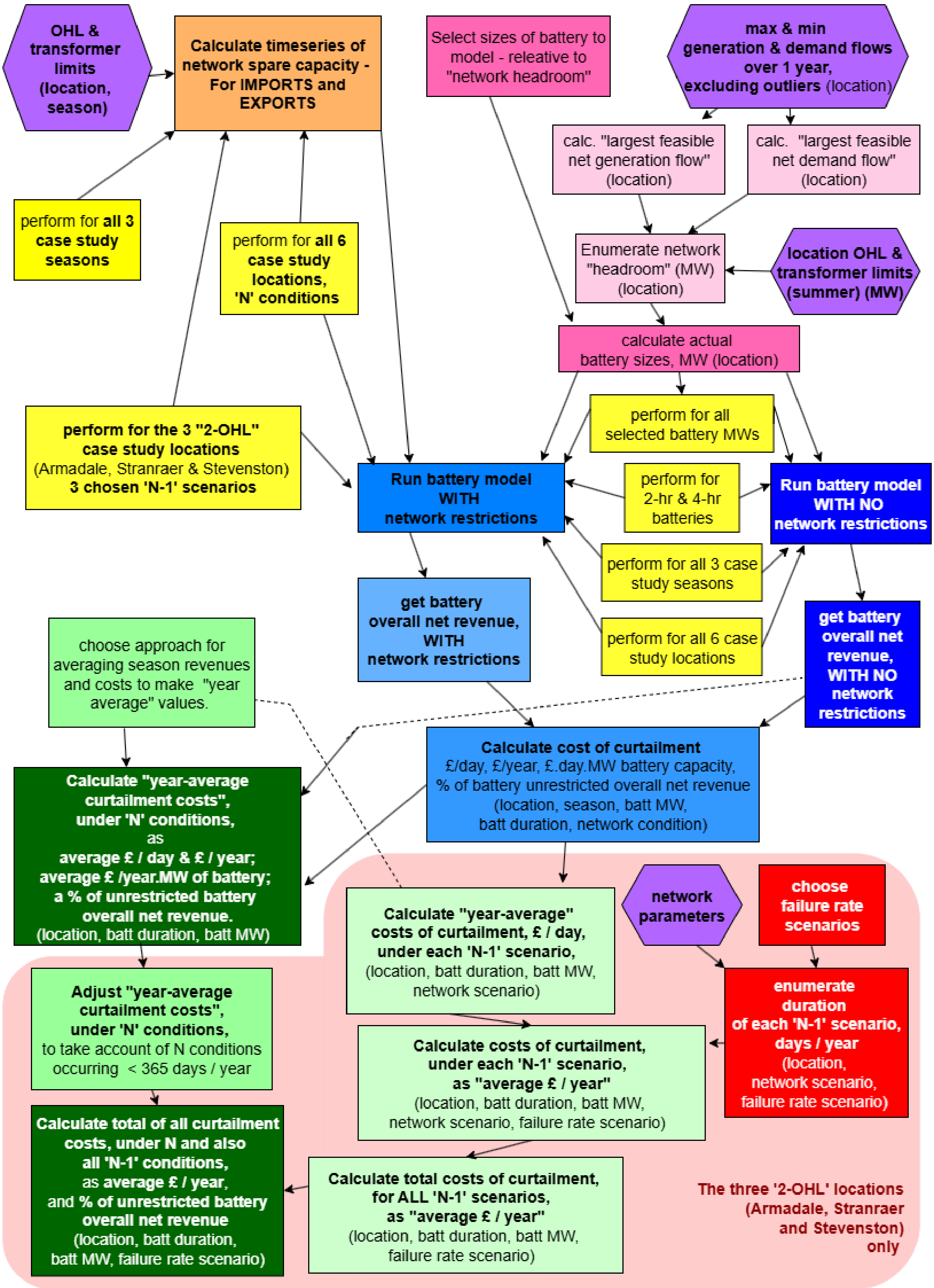


Figure 84 Flowchart summarising overall methodology for Chapter 7 [74]

[74] Purple hexagons – network data; pink boxes – sizing calculations; yellow boxes – scenarios chosen; blue boxes – battery simulations performed (with or without network restrictions); red boxes – failure rate scenarios; light green boxes – steps in calculating curtailment costs; dark green boxes – final calculations of curtailment costs; pink background – calculations taking account of 'N-1' conditions

7.3.1.1. Base case – battery simulation with no network constraints.

Battery simulations were run, as described in Chapter 4, using the same case study seasons, for batteries of 2 hour and 4 hour duration. Each simulation calculates the accumulated cashflow for that run. In every case, the trading scenario which allows the highest overall net revenue from the run was selected.

Later, simulations are performed for batteries of different capacities (MW), as described later. For any simulation run, using a battery of maximum export power *Pmax* MW, the accumulated cashflow at the end of the run, at time t, is shown in equation 7.1:

$$Accum\_cash(Pmax, t) = Pmax.Accum\_cash(1MW, t) \tag{7.1}$$

provided all other battery parameters (duration D, round trip efficiency η), trading parameters, and wholesale price timeseries data are unchanged.

7.3.1.2. Battery simulation with network constraints – overview

Simulations are then repeated, but with modification, to include network constraints. The only network constraints considered in this work are the thermal limits of the overhead lines and of the transformers. Other kinds of network limits, such as voltage rises or sags, or fault current, were not included in this analysis.

The amended battery model formulation is shown below:

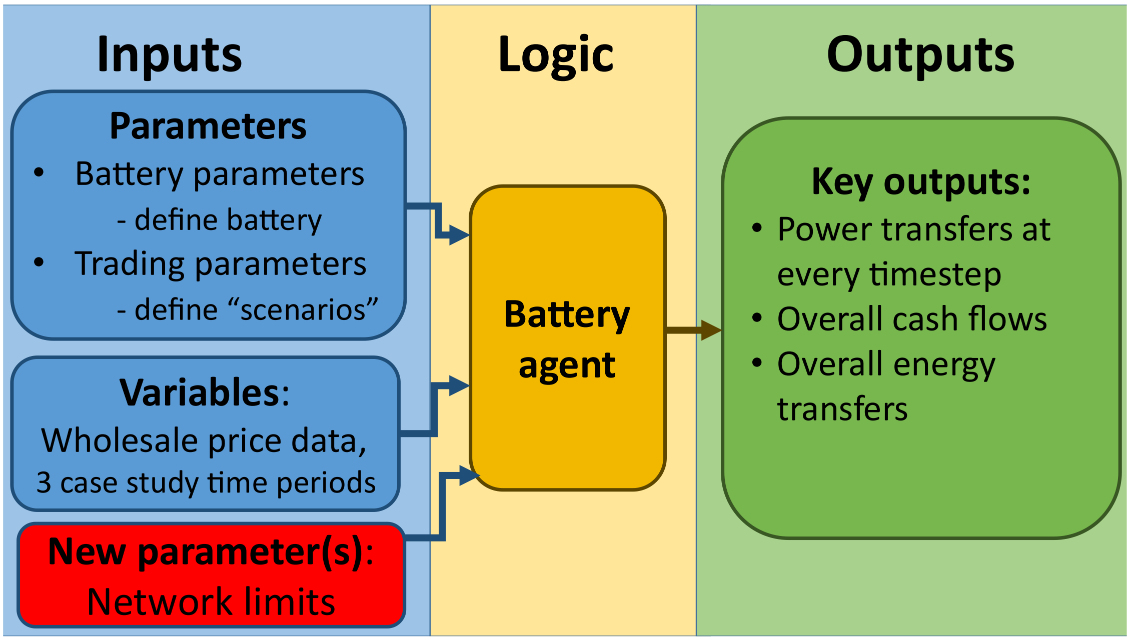


Figure 85 Battery model formulation amended to include network limits

Chapter 4 states that the export power of a battery, P(t), of maximum export power *Pmax*, at any timestep in which price conditions are favourable for the battery to export, in the absence of any network constraints, is:

$$P\ (t) = \ Pmax\ .\ \min\left(1, \quad (1 - SOC_{(t-1)}\ )\ \frac{D}{timestep}\right) \tag{4.36}$$

Which can be rearranged as follows:

$$P\ (t) = \min\left(Pmax, \quad Pmax.\, SOC_{(t\ -1)}.\frac{D}{timestep}\right) \tag{7.2}$$

Thus, for a constrained network, when exporting:

$$P\ (t) = \min\left(Pmax, \quad Pmax.\, SOC_{(t\ -1)}.\frac{D}{timestep}\ , network\_capacity_{(exporting,t)}\right) \tag{7.3}$$

Similarly, Chapter 6 states that the import power of a battery, P(t), at any timestep with price conditions that are favourable for a battery import, for an unconstrained network:

$$P\ (t) = -\ Pmax\ .\ \min\left(1, \quad (1 - SOC_{(t-1)}\ )\ \frac{D}{timestep\ .\eta}\right) \tag{4.42}$$

Rearranged as:

$$P\ (t) = -\ \min\left(Pmax, \quad Pmax.\,(1 - SOC_{(t-1)}\ )\ \frac{D}{timestep\ .\eta}\right) \tag{7.4}$$

Thus, for a constrained network, when importing:

$$P\ (t) = -\min\left(Pmax, \qquad Pmax.(1 - SOC_{(t-1)}).\frac{D}{timestep\ .\ \eta}\ ,\ network\_capacity_{(importing,t)}\right) \tag{7.5}$$

Enumeration of *network_capacity* is shown in Section 7.3.2.

For each case study season, and battery type (*Pmax*, duration *D*, round-trip efficiency η), and selected trading scenario, the accumulated cashflow *Accum_cash_constrained* from the simulation was found.

It is assumed that the battery operator has some foresight of the network constraints[75] . Thus, the trading scenario which allows the highest value of *Accum_cash_constrained* is chosen. These trading parameters may differ from the trading parameters which give best cashflow under unconstrained network conditions.

7.3.1.3. Cost of curtailment - overview.

The accumulated cashflow that a battery of parameters *Pmax*, *D*, η, accrued over a case study season, under conditions of network constraint, is compared with the accumulated cashflow accrued from the simulation under base case unconstrained conditions. The difference in net revenue, i.e. the net revenue forgone because of network constraints, is the cost of curtailment.

$$Curtailment\_cost = Accum\_cash\_unconstrained - Accum\_cash\_constrained$$

Calculation of curtailment cost is shown schematically in Figure 86.

[75] A battery operator could access information about network topology, assets connected to its network branch and their past activities, from open sources such as their DNO's published "heat map", Embedded Capacity Register, Long Term Development Statement, and Open Data Portal. An operator's local knowledge might help understand times of day when residential and any other demands are likely to be high and low. Knowledge of local weather conditions may help "guess" likely output from a local windfarm, where one is connected. Though this knowledge is likely to be incomplete or imperfect, it is considered a closer approximation than "no knowledge at all" scenario, in which case the battery agent is not be influenced by any considerations of other network users.

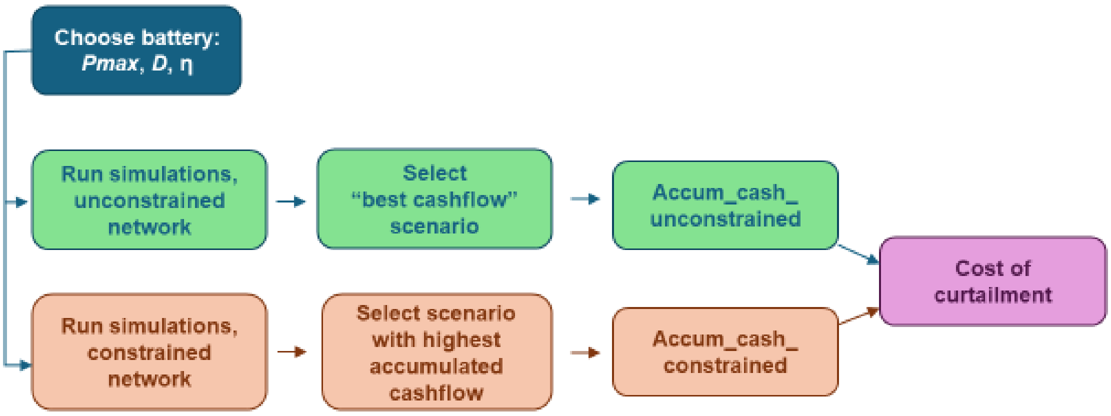


Figure 86 Schematic of enumeration of cost of curtailment where network constraints are present

Curtailment costs are initially enumerated as £ over the 35-day season, for that battery.

They are later expressed as average £ / day, £ / day.batt_MW, and as a percentage of accumulated net revenue under unrestricted conditions, in every case, over that season.

$$Curtailment\ cost_{season}(\frac{£}{day}) = \frac{curtailment\ cost_{season}(£)}{35days} \tag{7.6}$$

$$Curtailment\ cost_{season}\left(\frac{£}{day.MW}\right) = \frac{curtailment\ cost_{season}(£)}{35days.batt_{MW}} \tag{7.7}$$

$$Curtailment\ cost_{season}(\%) = \frac{curtailment\ cost_{season}(£) * 100}{Accum\_cash\_unconstrained_{season}(£)} \tag{7.8}$$

7.3.2. Enumeration of network capacity, selection of battery sizes (MW), and projection of annual revenues and costs

The same case study seasons as previously used, and the same case study locations as described in Chapter 6, are investigated further here.

This subsection is followed by subsection 7.3.3, which considers the three 2-feeder locations under abnormal ("N-1") conditions.

7.3.2.1. Enumeration of network capacity timeseries, at each location

The overhead line and transformer capacity limits used are all their normal ratings. A DNO Code of Practice [230] states that, unlike transformers, overhead lines have only continuous ratings at each applicable season, and neither cyclic nor emergency ratings. Regarding transformers, it is assumed that the DNO would apply a conservative approach and not allow the battery to access either emergency or cyclic ratings

Single-feeder circuit locations: Fairlie, Largs, Lochan Moor

Figure 87 shows the generic circuit arrangement for Fairlie, Largs and Lochan Moor, as described earlier in Chapter 6.

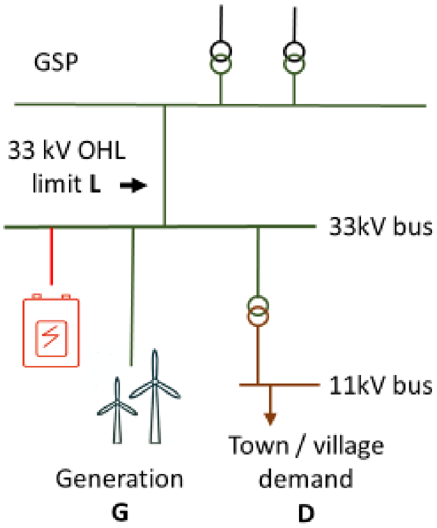


Figure 87 Circuit arrangement for Fairlie, Largs, Lochan Moor

Maximum rating of 33kV OHL:	***L*** (MW)
Generation from the windfarm:	***G*** (MW)
Demand from 11kV bus from town / village(s):	***D*** (MW)

The value of ***L*** varies with season, for each location.

Datasets for ***G*** and ***D*** are described in Chapter 6. As in Chapter 6, reactive power is neglected; D is demand net of any embedded generation at or below 11kV level. G(t) and D(t) here are both normally above zero.

At any timestep t, the available capacity of this circuit for battery exports is as shown in Eqn. 7.9.

$$network\ capacity\ (exporting, t) = L_{season} - G_t + D_t \tag{7.9}$$

And the network capacity for a battery import is as shown in Eqn. 7.10

$$network\ capacity\ (importing, t) = L_{season} + G_t - D_t \tag{7.10}$$

Two-feeder circuit locations: Armadale, Stevenston, Stranraer, normal operation ("N" conditions)

As described in Chapter 6, Armadale, Stevenston and Stranraer have 2 circuits connecting their 11kV bus to the GSP. All have a town demand; Armadale and Stranraer also have wind generation.

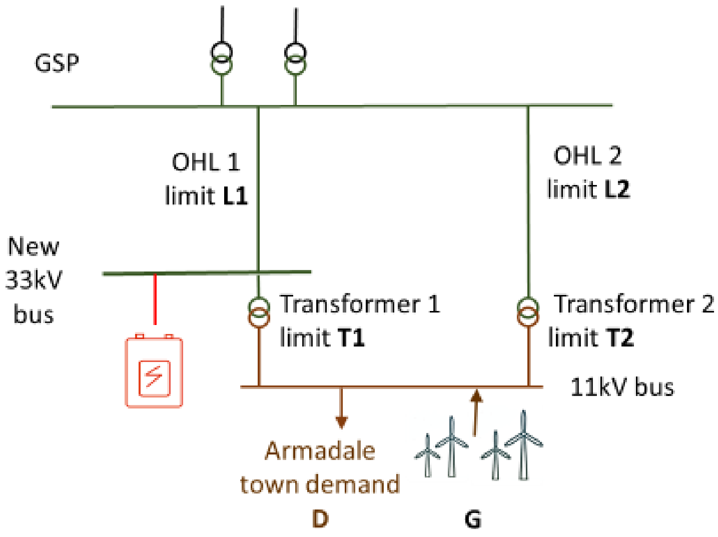


Figure 88 Circuit layout for Armadale

For Armadale,

$$\begin{aligned} &\textit{network capacity}\ (\text{Armadale, N}, \textit{exporting}, t) \\ &\qquad = L1_{season} \\ &\qquad + \min(T1, \quad (T2 + D_t - G_t), \quad (L2_{season} + D_t - G_t)\ ) \end{aligned} \tag{7.11}$$

$$\begin{aligned} &\textit{network capacity}\ (\text{Armadale, N}, \textit{importing}, t) \\ &\qquad = L1_{season} \\ &\qquad + \min(T1, \quad (T2 - D_t + G_t), \quad (L2_{season} - D_t + G_t)\ ) \end{aligned} \tag{7.12}$$

For Stevenston, having demand only at the 11kV bus and no generation, equations describing network capacity are similar, though there is no G(t).

$$\begin{aligned} &\textit{network capacity}\ (\text{Stevenston, N}, \textit{exporting}, t) \\ &\qquad = L1_{season} + \min(T1, \quad (T2 + D_t), \quad (L2_{season} + D_t)\ ) \end{aligned} \tag{7.13}$$

$$\begin{aligned} &\textit{network capacity}\ (\text{Stevenston, N}, \textit{importing}, t) \\ &\qquad = L1_{season} + \min(T1, \quad (T2 - D_t), \quad (L2_{season} - D_t)\ ) \end{aligned} \tag{7.14}$$

For Stranraer, slightly different equations apply as the windfarm is in a different position, as shown in

Figure 89.

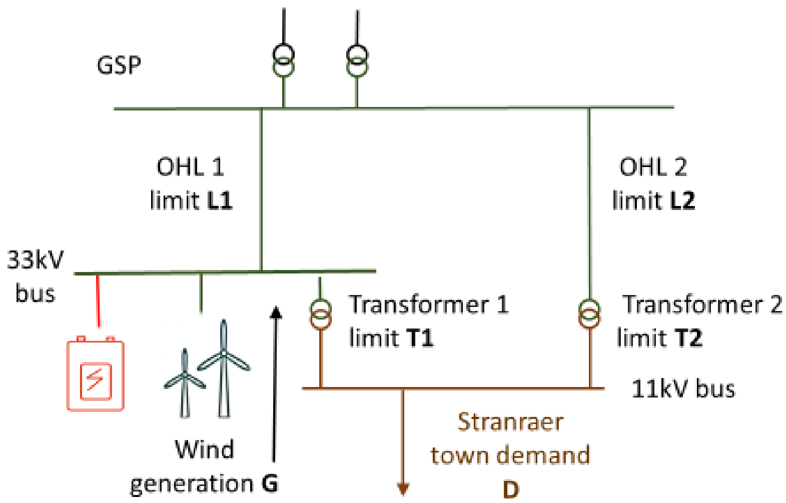


Figure 89 Circuit layout for Stranraer

$$network\ capacity\ (\text{Stranraer, N}, exporting, t) \\ = L1_{season} - G_t + \min(T1, \quad (T2 + D_t), \quad (L2_{season} + D_t)\ ) \tag{7.15}$$

$$network\ capacity\ (\text{Stranraer, N}, importing, t) \\ = L1_{season} + G_t + \min(T1, \quad (T2 - D_t), \quad (L2_{season} - D_t)\ ) \tag{7.16}$$

7.3.2.2. Selection of battery sizes simulated: sizing by network headroom

The case study locations have marked differences in existing capacity available for battery use. At one extreme, Lochan Moor has no spare capacity for any battery exports during periods of the windiest weather, having a windfarm connected with an agreed capacity that is approximately equal to the network capacity limit, and minimal import demands. In another case, Stevenston, spare import capacity available for a battery is constrained every single day according to the regular diurnal demand pattern, with no distribution-connected generation to reduce import flows. In contrast, Stranraer has significant unused network capacity, for both imports and exports, at all times. All windfarms in these case studies are connected with firm connections, i.e. the windfarms are not subject to any curtailment by the DNO.

To compare the effect of a battery at multiple locations together, battery sizing is performed *relative to the existing available network capacity, taking into account network limits and the magnitudes of generation and demands*.

Network "Headroom" here is defined as below:

H – network "headroom" available for battery use, under "worst case" demand and generation flows, where:

$$H = network\ limit - \max(largest\ feasible\ import\ flow, \quad largest\ feasible\ export\ flow) \tag{7.17}$$

D_{max} – highest half-hourly value of demand D

D_{min} – lowest half-hourly value of demand D

G_{max} - highest half-hourly value of wind generation G

G_{min} – lowest value of wind generation G

Unlike "network capacity", which varies from timestep to timestep, network *headroom* is defined as a fixed value for every location, based on highest feasible flows. The highest and lowest values of demands and generation were taken from a calendar year of data, data described in greater detail in Chapter 6. The data sources are shown in Table 37.

Table 37 Sources of data used in calculation of network headroom

	Source	**Dates**	**Resolution**
Generation (except Armadale)	BM data for actual or proxy windfarm	1 Jan - 31 Dec 2022	Half hourly
Generation – Armadale	SPEN open data portal dataset, modified, as described in Chapter 6	1 Sep 2022-31 Aug 2023	Half hourly
Demand	SPEN Open Data Portal dataset	1 Sep 2022-31 Aug 2023	Half hourly

Values of demand or generation considered anomalous (e.g. spikes in demand) were excluded. Further details are given in Appendix 1.

$$H = network\ limit - \max(\ (|D_{max}| - |G_{min}|), \quad (|G_{max}| - |D_{min}|)\ ) \tag{7.18}$$

“Largest feasible circuit flow” is defined as

$$largest\ feasible\ flow = \max(\ (|D_{max}| - |G_{min}|),\quad (|G_{max}| - |D_{min}|)\ ) \tag{7.19}$$

Here, the “network limit” is taken to be the *summer* MVA ratings for each relevant 33 kV OHL(s), these being tighter than other seasonal OHL limits and also the transformer ratings. Values of ‘maximum network flow’ at every location were calculated from values of ‘maximum generation’, ‘maximum demand’, ‘minimum generation’ and ‘minimum demand’, all of which are tabulated in Table 38. Further details on the selection of these values are given in Chapter 7 Annex 1.

Table 38 Highest and lowest network flow values – used in circuit headroom calculations

Place and flow type: Demand (Dem)/ Monitored Flow (MF)	**Demand / Import flows, MW**				**Generation / export flows, MW**				Max flow type	**Largest feasible import or export flow, for use in battery sizing, MW**
	Demand / import		Gen	Max overall import flow	Gen	Demand / import		Max overall export flow		
	Max value	Max demand value used	Min value	"Representative max import flow"	Max value	Min demand value[76]	Min demand value used	"Representative max export flow"		
Fairlie (MF & Dem)	*5.885 ([77])*	1.468	0	*1.50*	14	0.114	0.179	**13.8**	Generation	**13.8**
Largs (MF)	*7.805*	7.71	0	*7.7*	14	0.312	0.346	**13.65**	Generation	**13.65**
Lochan Moor (MF)	*4.889*	4.764	0	*4.8*	22	-0.749	0	**22.0**	Generation	**22.0**
Armadale (Dem)	*13.408*	12.726	0	*12.7*	17.91	-10.8	0.998 ([78])	**16.922**	Generation	**16.922**
Stranraer (MF & Dem)	*24.756*	**11.764**	0	**11.734**	13	2.938	3.013	*9.99*	Demand	**11.734**
Stevenston (MF &Dem)	*19.791*	**13.354**	0	**13.354**	0	3.929	4.079	*-4.1*	Demand	**13.354**

The boxes shaded in green contain the values used in later calculations.

[76] In Lochan Moor, there were some consistent slightly negative values of demand, presumed to be some small embedded generation. In Armadale, negative demand values were presumed to be miscalculations, as described in Annex 1.
[77] In Fairlie, exceptionally high demands of 1.5-5.9 MW only occurred during several brief occasions during 2023: on 2 May, and between 26 June and 1 July, lasting altogether for less than 4 days over the year. These values were considered anomalous and they were are not used in circuit headroom calculations.
[78] The value at Armadale used is the 25th-smallest value of re-calculated demand. The negative and very low positive values are believed to be from incorrect reported generation figures reported in SPEN's Open Data Portal. More info on rescaling and recalculating of generation and demand at Armadale is given in Annex 7 of Chapter 7.

7.3.2.3. *Selection of sizes of batteries to use in simulations*

Single-feeder circuit locations Fairlie, Largs and Lochan Moor

The network headroom ***H*** for each location is determined from the OHL summer circuit limit (previously shown in Chapter 6) and the "largest feasible import or export flow", shown in Table 38.

$$H = L_{summer} - largest\ feasible\ flow \qquad (7.20)$$

The values of network headroom H for the Fairlie, Largs and Lochan Moor are tabulated in Table 39.

Table 39 Values of network headroom for Fairlie, Largs and Lochan Moor

Location	Summer OHL rating, MVA	Max feasible flow, MW	Max feasible flow type	H, MW
Fairlie	20.86	13.8	Generation	7.0
Largs	20.9	13.65	Generation	7.2
Lochan Moor	21.6	22.0	Generation	0

Batteries were simulated sized from 0 to 20 MW in excess of network headroom, as tabulated in Table 40. For any battery of size ***'x'*** in excess of network headroom, battery capacity ***Pmax*** is described by

$$Pmax = H_{location} + x \qquad (7.21)$$

Table 40 Battery sizes and headroom exceedances modelled for Fairlie, Largs and Lochan Moor

Place	**Parameter**	**Network Headroom Exceedances ('x'), and Modelled Battery Capacities , MW**								
All	**Exceedance of network headroom, 'x', MW**	**0**	**2.5**	**5**	**7.5**	**10**	**12.5**	**15**	**17.5**	**20**
Fairlie	**Modelled battery capacities, Pmax, MW**	7	9.5	12	14.5	17	19.5	22	24.5	27
Largs		7.2	9.7	12.2	14.7	17.2	19.7	22.2	24.7	27.2
Lochan Moor		-	2.5	5	7.5	10	12.5	15	17.5	20

Simulations were run, using batteries of the sizes shown in Table 40, for both unconstrained (base case) and then with network constraints, as described in Section 7.3.1 above.

Two-feeder circuit locations: Armadale, Stevenston and Stranraer

Similarly, largest feasible flow values (excluding brief overcurrent spikes), and network headroom values H, under normal "N" conditions in which both circuit branches active, are described by the equation below:

$$H_N = L1_{summer} + L2_{summer} - \ largest\ feasible\ flow \tag{7.22}$$

The values of L1, L2, maximum feasible flows, and 'H_N', are shown Table 41.

Table 41 Values of network headroom for Armadale, Stevenston and Stranraer (normal "N" conditions)

Location	Summer OHL rating, MVA		Largest feasible flow, MW	Largest feasible flow type	H ("N"), MW across both branches Line 1 and Line 2
	L1	L2			
Armadale	19.71	19.71	**16.922**	Generation	22.5
Stevenston	19.71	16.29	**13.354**	Demand	22.6
Stranraer	19.71	19.71	**11.734**	Demand	27.7

Batteries sized from 0 to 40 MW in excess of network headroom (under "N" conditions) were simulated, as tabulated in Table 42.

Under normal "N" circuit conditions considered here,

$$Pmax = H_{\_N\_location} + x\_N \tag{7.23}$$

Table 42 Battery sizes and headroom exceedances modelled for Armadale, Stevenston and Stranraer (normal “N” conditions)

Place	Parameter	Headroom Exceedances (‘x_N’) and Modelled Battery Capacities, MW																			
All	**Exceedance of Headroom, N conditions, ‘x_N’, MW**	-17.5	-15	-12.5	-10	-7.5	-5	-2.5	**0**	**2.5**	**5**	**7.5**	**10**	**12.5**	**15**	**17.5**	**20**	**25**	**30**	**35**	**40**
Arma-dale	**Modelled Battery Capacities, Pmax, MW**	**5**	**7.5**	**10**	**12.5**	**15**	**17.5**	**20**	22.5	25	27.5	30	32.5	35	37.5	40	42.5	47.5	52.5	57.5	62.5
Steven-ston		**5.1**	**7.6**	**10.1**	**12.6**	**15.1**	**17.6**	**20.1**	22.6	25.1	27.6	30.1	32.6	35.1	37.6	40.1	42.6	47.6	52.6	57.6	62.6
Stran-raer		**10.2**	**12.7**	**15.2**	**17.7**	**20.2**	**22.7**	**25.2**	27.7	30.2	32.7	35.2	37.7	40.2	42.7	45.2	47.7	52.7	57.7	62.7	67.7

The battery sizes corresponding to negative values of network headroom are relevant in later analysis of abnormal “N-1” network conditions, described later in Section 7.3.3 and tabulated in Table 51.

7.3.2.4. Projections of average annual net revenues and curtailment costs

Each simulation result of net revenue and curtailment cost is specific to the location, battery size, and the case-study season. Average *daily* curtailment costs are obtained for each run.

For every location, battery size and network condition, "*year average*" estimations of overall net revenues and curtailment costs are made, based on the three season-based projections of annual curtailment costs. These "*year average"* costs are the weighted sums of the costs for the three case study periods, with a 50%, 25%, and 25% weighting corresponding to the autumn, summer and winter case studies, respectively.

i.e. these projections assume that half the year is "mid-season", like the autumn case study period; they assume that a quarter of the year is "like winter"; and a quarter of the year is "like the summer case study".

$$average\ annual\ cost\ = \frac{1}{2} * autumn\ cost + \frac{1}{4} * summer\ cost + \frac{1}{4} * winter\ cost \qquad (7.24)$$

The above equation also applies to season-based net revenues from battery trades.

These year-average costs need to be viewed as approximate; however, they simplify presentation of results and the viewing of the effect of location, and of battery capacity in exceedance of network headroom.

7.3.3. Consideration of abnormal circuit conditions

7.3.3.1. Scope of study

This section investigates scenarios in which a part of the network is unavailable. This situation is relevant for all batteries connected with non-firm connections, and also for batteries connected with firm connections, as recommended by the ENA's Tactical Solution 1, as described in Section 7.2.3.

Three of the case study locations have two OHLs connecting the 11kV buses to GSP (Armadale, Stranraer, Stevenston). As shown in Chapter 6, in all these three locations, demand and wind generation flows at all times fell within the limits of either of the individual circuit branches. Thus, a failure or planned maintenance in one OHL or transformer (i.e. an "N-1" condition) should not interrupt supply to the town nor the ability of the windfarm to export; security standard EREC P2/8 [77] would not mandate immediate repair. However, such a situation would greatly reduce the circuit capacity available for battery use, for any battery connected with either a non-firm connection, or a firm connection with conditions of the ENA's Tactical Solution 1, as described earlier in Section 7.2.3.

At the other three locations, Fairlie, Largs, Lochan Moor, connected with a single feeder to GSP (i.e. under "N" security conditions), any failure in the OHL or 33/11kV transformer would disconnect supply to the entire town / village(s). It is assumed that repair would be prompt, and this situation is not investigated. (The ENA's Tactical Solution 1 would not propose any change of circumstance for this situation.)

7.3.3.2. Key assumptions

This study assumes that failure frequencies are as per long-term average failure rates, of which three failure rate scenarios are investigated.

Given that the numbers of days per year of abnormal conditions is relatively small, failures in different components are assumed to occur non-coincidentally, and that the expected numbers of days per year of duration of different failure modes can be summed. Clearly a more detailed study would use probabilistic modelling for greater accuracy; this initial study seeks to explore the magnitude of curtailment costs under *abnormal* network operating conditions, and whether these costs appear significant enough to merit further investigation.

7.3.3.3. Network scenarios considered

Three different scenarios for "N-1" conditions were modelled:

- Network N-1 scenario 1: All battery, generation and demand flows via OHL 1 i.e. either OHL 2 or Transformer 2 inoperable Figure 90

Network N-1 scenario 2: All battery, generation and demand flows via OHL 2. i.e. OHL 1 inoperable. All battery flows routed via 11kV bus. (

- Figure 91 and Figure 92).
- Network N-1 scenario 3: Transformer 1 inoperable. Battery flows (and for Stranraer, also windfarm generation) via OHL 1. 11kV demand flows (and for Armadale only, also wind generation) via OHL 2 (not modelled). (Figure 93 and Figure 94)

The circuit arrangements for these three "N-1" scenarios are illustrated below.

Network N-1 scenario 1: OHL 2 or Transformer 2 not operational

The event that either OHL 2 or Transformer 2 is unavailable, but Line 1 (the branch to which the battery is attached) and Transformer 1 are both working normally is illustrated in Figure 90 (for Armadale).

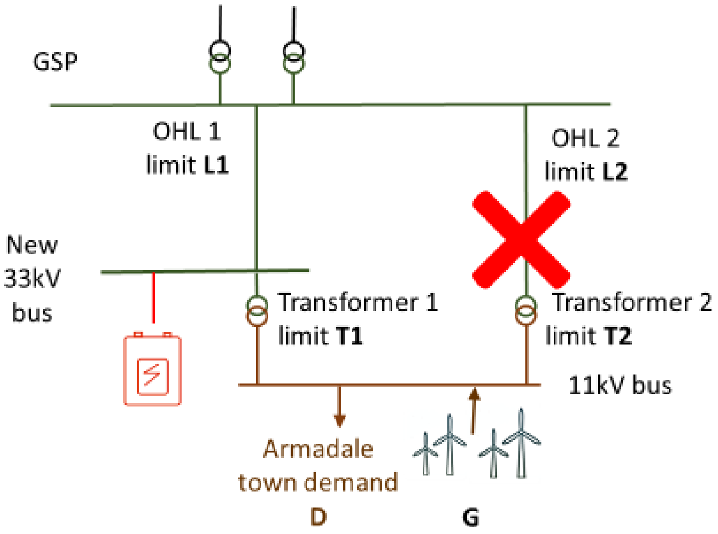


Figure 90 Armadale, N-1 scenario 1: OHL 2 or Transformer 2 not operational

For all three locations, the following equations apply:

$$network\ capcity\ (\text{N-1 (line2 unavailable)}, exporting, t) \tag{7.25}$$

$$= L1_{season} + D_t - G_t$$

$$network\ capcity\ (\text{ N-1 (line2 unavailable)}, importing, t) \tag{7.26}$$

$$= L1_{season} - D_t + G_t$$

In the case of Stevenston, G(t) = 0.

Network N-1 scenario 2: OHL 1 not operational

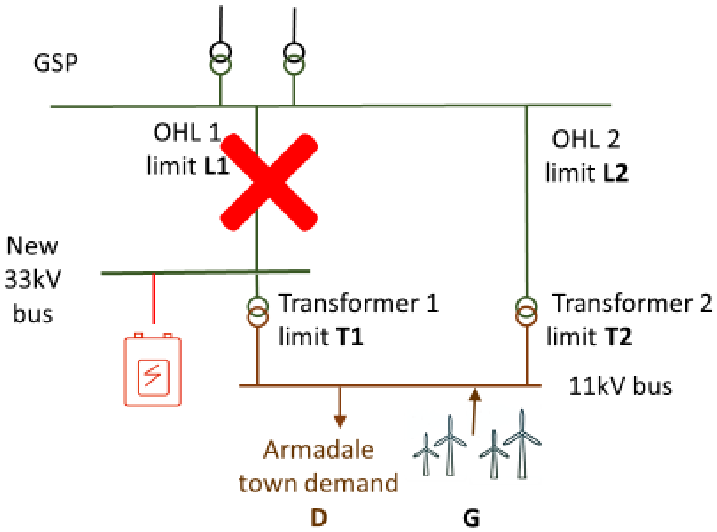


Figure 91 Armadale circuit arrangement. N-1 scenario 2: OHL line 1 unavailable

In the event that Line 1 is not working but Line 2 is functioning normally, it is assumed that the battery flows can be routed via the 11kV bus. No capacity limits for the bus are listed in DNO information, so maximum flows are deemed to be limited by one or both of the transformers and OHL 2. As illustrated for Armadale in

Figure 91, network capacity is often the same as shown above, but under some conditions of D(t) and G(t) overall network capacity will be restricted by the capacity of one of the transformers.

$$network\ capacity\ (\text{Armadale, N-1 (line1 unavailable)}, exporting, t)$$

$$= \min(T1, \quad (T2 + D_t - G_t), \quad (L2_{season} + D_t - G_t)\ ) \tag{7.27}$$

$$network\ capcity\ (\text{Armadale, N-1 (line1 unavailable)}, importing, t)$$

$$= \min(T1, \quad (T2 - D_t + G_t), \quad (L2_{season} - D_t + G_t)\ ) \tag{7.28}$$

Similar equations apply for Stevenston, but the term G(t) = 0 and can be omitted.

For Stranraer, the circuit arrangement is illustrated Figure 92. Slightly different equation apply:

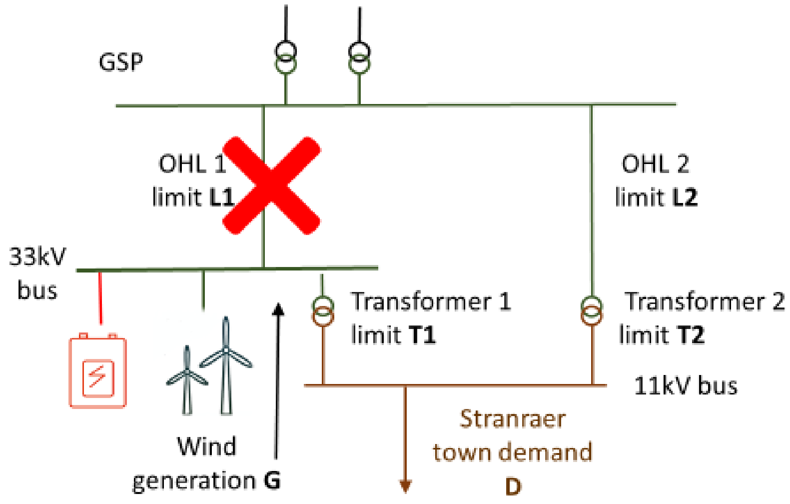


Figure 92 Stranraer circuit arrangement. N-1 scenario 2: OHL line 1 unavailable

$$network\ capacity\ (\text{Stranraer, N-1(line1 unavailable)}, exporting, t)$$

$$= -G_t + \min(T1, \quad (T2 + D_t), \quad (L2_{season} + D_t)\ ) \tag{7.29}$$

$$network\ capacity\ (\text{Stranraer, N-1(line1 unavailable)}, importing, t)$$

$$= +G_t + \min(T1, \quad (T2 - D_t), \quad (L2_{season} - D_t)\ ) \tag{7.30}$$

Network N-1 scenario 3: Transformer 1 not operational

Under circumstances of Transformer 1 being unavailable, and the 33kV bus to which the battery connects being unaffected, then the network capacity is as shown below.

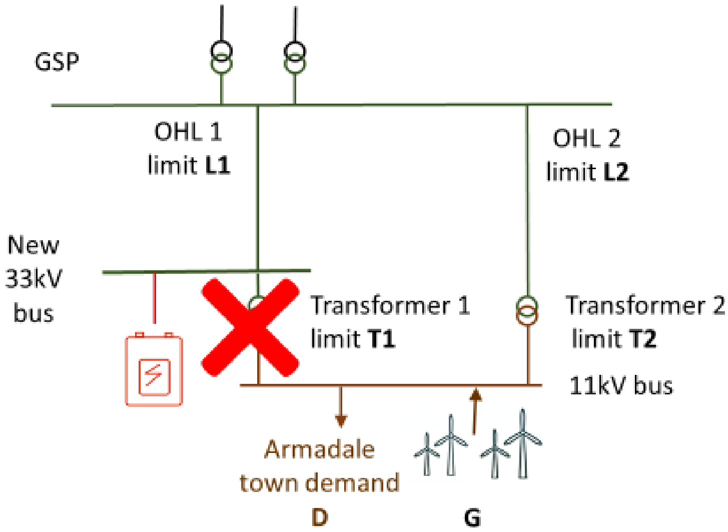


Figure 93 Armadale circuit. N-1 scenario 3: Transformer 1 unavailable

For Armadale and Stevenston, for both imports and exports

$$network\ capacity\ (\text{N-1(Transformer1 unavailable)}) = L1_{season} \tag{7.31}$$

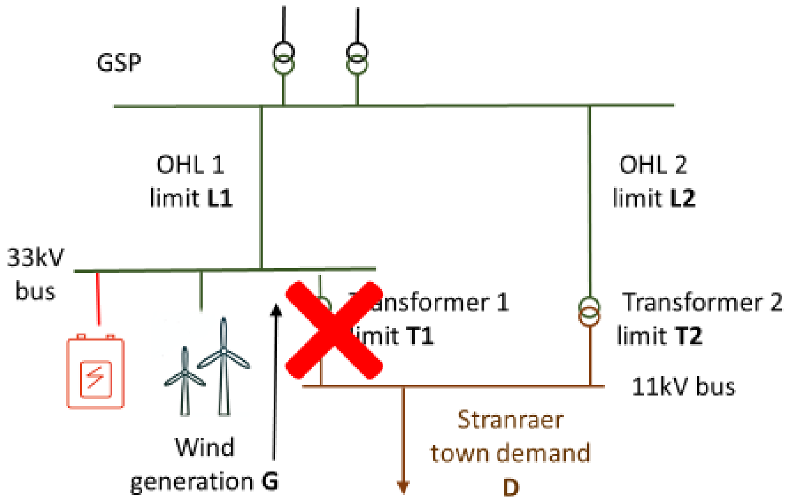


Figure 94 Stranraer circuit. N-1 scenario 3: Transformer 1 unavailable

For Stranraer,

$$network\ capacity\ (\text{N-1(Transformer1 unavailable)}, exporting, t) = L1_{season} - G_t \tag{7.32}$$

$$network\ capacity\ (\text{N-1(Transformer1 unavailable)}, importing, t) = L1_{season} + G_t \tag{7.33}$$

7.3.3.4. Frequency and duration of occurrences

Imperial College London's 2015 *Review of Distribution Security Standards. Extended Report Table 2.28 page 48* [248] states failure rates and repair times for the relevant network components, as shown in Table 43. This source uses "low" and "high" failure rate scenarios. A further "medium" failure rate scenario was proposed, using failure rates of the arithmetic mean of the "low" and "high" failure rate scenarios.

Table 43 Failure rates and outage times for EHV distribution network components [248]

<table>
<tr><th rowspan="2">Fail rate scenario</th><th colspan="2">33kV OHL</th><th colspan="2">Transformer</th><th colspan="2">Transformer feeder</th><th rowspan="2">Source</th></tr>
<tr><th>Failure rate / km. year</th><th>Mean Time To Repair, hours</th><th>Failure rate / year</th><th>Mean Time To Repair, hours</th><th>Failure rate</th><th>Outage duration, hours</th></tr>
<tr><td>"Low"</td><td>2%</td><td>120</td><td>1%</td><td>720</td><td rowspan="2">1 in 8 years</td><td rowspan="2">120</td><td>[248]</td></tr>
<tr><td>"High"</td><td>15%</td><td>120</td><td>10%</td><td>720</td><td>[248]</td></tr>
<tr><td>"Medium"</td><td>8.5%</td><td>120</td><td>5.5%</td><td>720</td><td>1 in 8 years</td><td>120</td><td>Arithmetic mean of "Low" and "High" scenario values</td></tr>
</table>

Feeder outages:

$$no\frac{days}{yr}(N-1)conditions$$
$$= failure\,rate(perkm.yr) * branch\ length(km) * MTTR(days) \qquad (7.34)$$

Transformer outages:

$$no\frac{days}{yr}(N-1)conditions = failure\ rate * MTTR(days) \qquad (7.35)$$

For the low, medium and high failure rate scenarios, the resultant average number of days / year of unavailability of key network components are shown in Table 44, Table 45 and Table 46, respectively. Durations of the three different "N-1" scenarios, and of full "N" conditions, for the three failure rate scenarios are shown in Table 47, Table 48 and Table 49.

Table 44 Armadale, Stevenston and Stranraer. Expected durations of network components' unavailability, "low failure rate" scenario

Location	OHL 1 (battery direct connection)				OHL 2 (indirect battery connection)				Transformer 1 Also Transformer 2.					OHL 2 + Tr. 2
	OHL length, km	Annual failure rate, at 2%/km. y	MTTR, days	Average no. of days / year unavailable	OHL length km	Annual failure rate, at 2% /km. y	MTTR, days	Average no of days / year unavailable	Annual failure rate, at 1%/y	MTTR, days	Feeder repair, no/year	MTTR, days	Average days un-available / year	Av. days / year un-avail.
Armadale	1.84	0.04	5	0.2	1.85	0.04	5	0.2	0.01	30	0.125	5	0.9	1.1
Stevenston	3.66	0.07	5	0.4	3.74	0.07	5	0.4						1.3
Stranraer	15.1	0.3	5	1.5	13.6	0.27	5	1.4						2.3

Table 45 Armadale, Stevenston and Stranraer. Expected durations of network components' unavailability, "medium failure rate" scenario

Location	OHL 1 (battery direct connection)				OHL 2 (indirect battery connection)				Transformer 1 Also Transformer 2.					OHL 2 + Tr. 2
	OHL length, km	Annual failure rate, at 8.5%/km y	MTTR, days	Average no. of days / y unavail.	OHL length, km	Annual failure rate, at 8.5% /km. y	MTTR, days	Average no of days / y unavail.	Annual failure rate, at 5.5%/y	MTTR, days	Feeder repair, no/year	MTTR, days	Average days un-available / year	Av. days / year un-avail.
Armadale	1.84	0.2	5	0.8	1.85	0.2	5	0.8	0.055	30	0.125	5	2.3	3.1
Stevenston	3.66	0.3	5	1.6	3.74	0.3	5	1.6						3.9
Stranraer	15.1	1.3	5	6.4	13.6	1.2	5	5.8						8.1

Table 46 Armadale, Stevenston and Stranraer. Expected durations of network components' unavailability, " high failure rate" scenario

Location	OHL 1 (battery direct connection)				OHL 2 (indirect battery connection)				Transformer 1 Also Transformer 2.					OHL 2 + Tr. 2
	OHL length, km	Annual failure rate, at 15%/km y	MTTR days	Average no. of days / year unavailable	OHL length, km	Annual failure rate, at 15%/km.y	MTTR, days	Average no of days / year unavailable	Annual failure rate, at 10% / y	MTTR, days	Feeder repair, no/year	MTTR, days	Average days un-available / year	Av. days / y unavail.
Armadale	1.84	0.3	5	1.4	1.85	0.3	5	1.4	0.1	30	0.125	5	3.6	5.0
Stevenston	3.66	0.5	5	2.7	3.74	0.6	5	2.8						6.4
Stranraer	15.1	2.3	5	11.3	13.6	2.0	5	10.2						13.8

Table 47 Armadale, Stevenston and Stranraer. Average durations of abnormal ("N-1") and normal ("N") network conditions, low failure rate scenario

Location	Average number of days / year				Percentage of year	
	"N-1" conditions			Normal "N" operation	Any "N-1" condition occurs	Normal "N" operation
	N-1 scenario 1: OHL 2 OR T2 inoperable	N-1 scenario 2: OHL 1 inoperable	Network N-1 scenario 3: T1 inoperable			
Armadale	1.1	0.2	0.9	363	0.6%	99.4%
Stevenston	1.3	0.4	0.9	363	0.7%	99.3%
Stranraer	2.3	1.5	0.9	361	1.3%	98.7%

Table 48 Armadale, Stevenston and Stranraer. Average durations of abnormal ("N-1") and normal ("N") network conditions, medium failure rate scenario

Location	Average number of days / year				Percentage of year	
	"N-1" conditions			Normal "N" operation	Any "N-1" condition occurs	Normal "N" operation
	N-1 scenario 1: OHL 2 OR T2 inoperable	N-1 scenario 2: OHL 1 inoperable	N-1 scenario 3: T1 inoperable			
Armadale	3.1	0.8	2.3	359	1.7%	98.3%
Stevenston	3.9	1.6	2.3	357	2.1%	97.9%
Stranraer	8.1	6.4	2.3	349	4.6%	95.4%

Table 49 Armadale, Stevenston and Stranraer. Average durations of abnormal ("N-1") and normal ("N") network conditions, high failure rate scenario

Location	Average number of days / year				Percentage of year	
	"N-1" conditions			Normal "N" operation	Any "N-1" condition occurs	Normal "N" operation
	N-1 scenario 1: OHL 2 OR T2 inoperable	N-1 scenario 2: OHL 1 inoperable	N-1 scenario 3: T1 inoperable			
Armadale	5.0	1.4	3.6	355	2.7%	97.3%
Stevenston	6.4	2.7	3.6	352	3.5%	96.5%
Stranraer	13.8	11.3	3.6	336	7.9%	92.1%

7.3.3.5. *Approach to modelling battery curtailment – network headroom*

Simulations were conducted using the same battery sizes as under "N" conditions, as described above, but extending down to smaller sizes.

Clearly the "headroom" of the circuit under "N-1" conditions, $H_{N-1,}$ is much smaller than the headroom under "N" conditions, H_N:

For any given value of H_N:

$$H_{N-1(LIne1)} = H_N - L2 \tag{7.36}$$

$$H_{N-1(LIne2)} = H_N - L1 \tag{7.37}$$

$$H_{N-1(Line\ 1)} = L1 - \ largest\ feasible\ flow \tag{7.38}$$

For Stevenston only, in which L2 differs from L1,

$$H_{N-1(Line2)} = L2 - \ largest\ feasible\ flow \tag{7.39}$$

Network headroom values relative to single as well as both circuit branches are tabulated in Table 50.

Table 50 Values of network headroom for Armadale, Stevenston and Stranraer. Normal "N" and abnormal "N-1" conditions

Location	Summer OHL rating, MVA		Max feasible flow, MW	Max feasible flow type	H ("N-1"), MW Across single branch		H ("N"), MW across both branches Line 1 and Line 2
	L1	L2			Line 1	Line 2	
Armadale	19.71	19.71	**16.922**	Generation	2.8	2.8	22.5
Stevenston	19.71	16.29	**13.354**	Demand	6.4	2.9	22.6
Stranraer	19.71	19.71	**11.734**	Demand	8.0	8.0	22.7

Modelled battery capacities are tabulated in Table 51, a table which expands on Table 42 to include battery sizes with respect to 'N-1' network conditions

Key for Table 51:

Parameter	Colour used
Actual battery sizes, Pmax, modelled at each location	
Selected battery sizes *in excess of network headroom* under N conditions, 'x_N' modelled at every location (values > 0 MW)	
Selected battery sizes *in excess of network headroom* under N-1 conditions, 'x_'N-1', modelled at every location. (Values > 0 MW)	
Selected battery sizes *in excess of network headroom* (N conditions) 'x_'N-1' with respect to "line 2", Stevenston only. (Values > 0 MW)	
Any selected battery sizes in excess of network headroom, under either N conditions, 'x_N' or N-1 conditions, x_N-1'), where values < 0 MW	

7.3.3.6. Season-based and average annual results

As for revenues and curtailment costs under "N" conditions, curtailment costs under "N-1" conditions are obtained as season-based averages for each season, i.e. assuming that the whole year is like that case study season.

"Year-averaged" curtailment costs are also obtained, using the same approach as in Section 7.3.2.4 for "N" curtailment costs. These "year-averaged, N-1" curtailment costs aim to represent the curtailment costs of "N-1" events being evenly spread across the year.

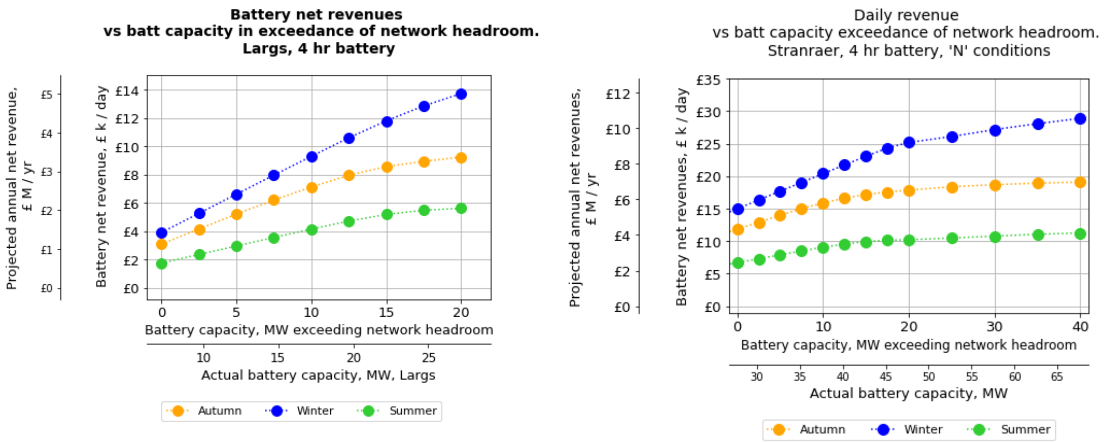
Table 51 Battery sizes modelled for Armadale, Stevenston and Stranraer , with headroom exceedances relative to normal and abnormal conditions

Place	Parameter	Headroom Exceedances ('x_N' and 'x_N-1'), and Modelled Battery Capacities, MW																			
	Exceedance of Headroom, N conditions, 'x_'N' '	-17.5	-15	-12.5	-10	-7.5	-5	-2.5	0	2.5	5	7.5	10	12.5	15	17.5	20	25	30	35	40
Arma-dale	**Batt size Pmax**	**5**	**7.5**	**10**	**12.5**	**15**	**17.5**	**20**	**22.5**	**25**	**27.5**	**30**	**32.5**	**35**	**37.5**	**40**	**42.5**	**47.5**	**52.5**	**57.5**	**62.5**
	Exceedance of N-1 headroom 'x_'N-1' '	2.2	4.7	7.2	9.7	12.2	14.7	17.2	19.7	22.2	24.7	27.2	29.7	32.2	34.7	37.2	39.7	44.7	49.7	54.7	59.7
Steven-ston	**Batt size Pmax**	**5.1**	**7.6**	**10.1**	**12.6**	**15.1**	**17.6**	**20.1**	**22.6**	**25.1**	**27.6**	**30.1**	**32.6**	**35.1**	**37.6**	**40.1**	**42.6**	**47.6**	**52.6**	**57.6**	**62.6**
	Exceedance of N-1 headroom, Line 1, 'x_'N-1' (Line 1)'	-1.2	1.3	3.8	6.3	8.8	11.3	13.8	16.3	18.8	21.3	23.8	26.3	28.8	31.3	33.8	36.3	41.3	46.3	51.3	56.3
	Exceedance of N-1 headroom, Line 2, 'x_'N-1' (Line 2)'	2.2	4.7	7.2	9.7	12.2	14.7	17.2	19.7	22.2	24.7	27.2	29.7	32.2	34.7	37.2	39.7	44.7	49.7	54.7	59.7
Stran-raer	**Batt size Pmax**	**10.2**	**12.7**	**15.2**	**17.7**	**20.2**	**22.7**	**25.2**	**27.7**	**30.2**	**32.7**	**35.2**	**37.7**	**40.2**	**42.7**	**45.2**	**47.7**	**52.7**	**57.7**	**62.7**	**67.7**
	Exceedance of N-1 headroom 'x_'N-1' '	2.2	4.7	7.2	9.7	12.2	14.7	17.2	19.7	22.2	24.7	27.2	29.7	32.2	34.7	37.2	39.7	44.7	49.7	54.7	59.7

7.4. Results.

7.4.1. The effect of network restrictions on battery overall revenues.

Two locations (Largs, one of the single-branch locations, and Stranraer, one of the 2-branch locations) are shown here to illustrate how overall battery net revenues (i.e. overall cashflows from energy trading) vary with battery size, at the three case study season, in circumstances of network restrictions.

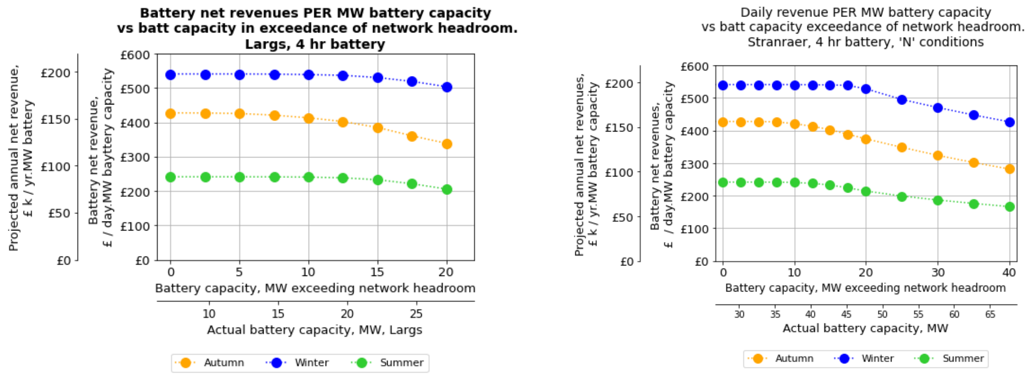


(a) Largs (b) Stranraer

Figure 95 Overall net battery revenues, £k/day, and projected £M / year, vs battery capacity. (a) Largs, (b) Stranraer. Both - 4-hour battery, all seasons

Figure 95 shows how net revenues initially increase linearly with increasing battery size, as expected. However, at larger battery sizes, increases in net revenues are lower, because of network restrictions. These charts also display the significant difference in incomes between the case study seasons, as discussed in Chapter 4.

The effect of network restrictions in limiting battery net revenues at larger battery size can be seen more clearly in Figure 96, which plots net revenue per MW of battery capacity. Initially, net revenues £ / MW battery capacity do not change with battery size, but at larger battery sizes, income per MW battery capacity falls with increasing battery capacity.

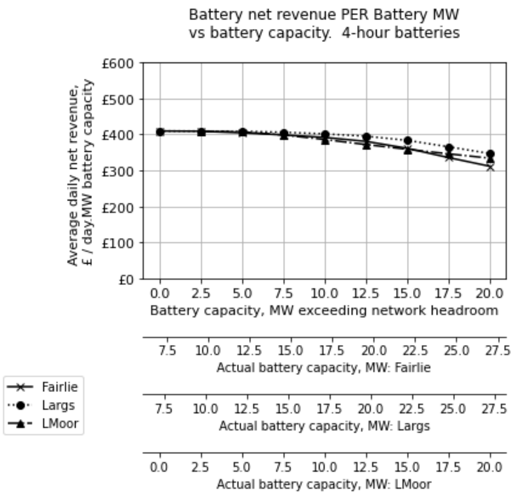


(a) Largs (b) Stranraer

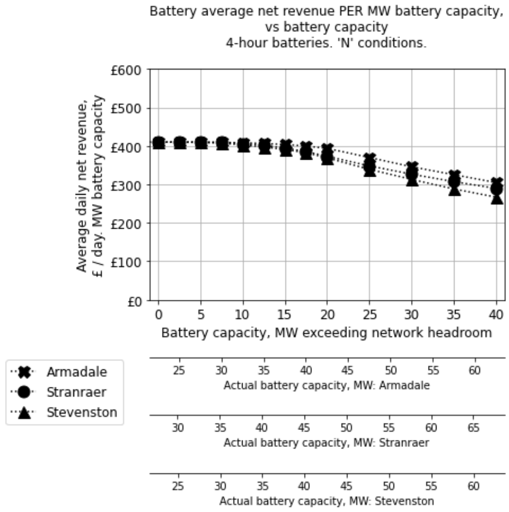
Figure 96 Net battery revenues PER MW of battery capacity, vs battery capacity. Largs and Stranraer, both 4-hour battery, all seasons

Full results are appended in Chapter 7 Annex 2.

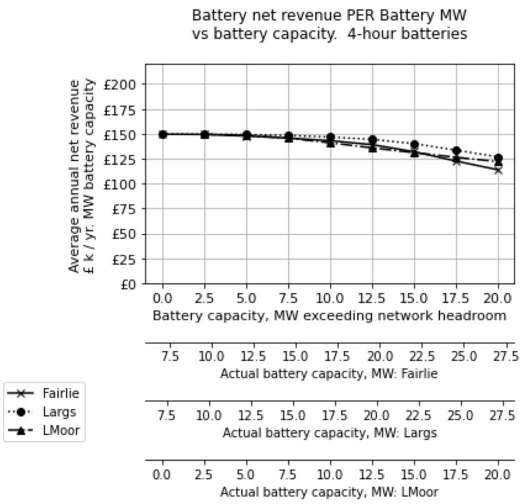
Figure 97 shows the same behaviour as Figure 96, though in this plot the overall net revenues from battery trades are averaged across the seasons, as described in Section 7.3.2.4. This plot also shows that a battery, sized with a small exceedance of network headroom, connected at every location, would accrue the same revenue per MW battery size, as expected, and that their revenues would be similarly affected by increasing battery size. Full results are appended in Chapter 7 Annex 2.



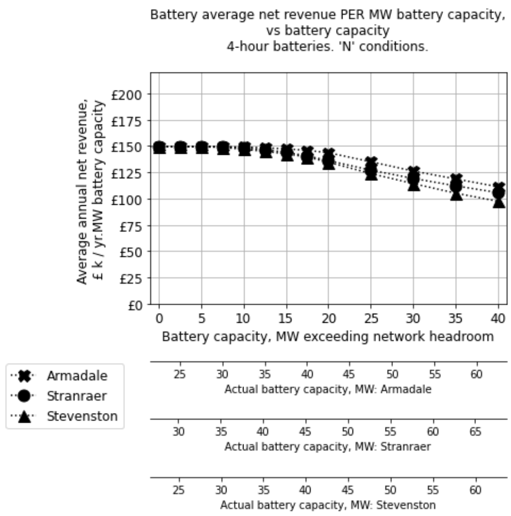
(a)



(b)



(c)

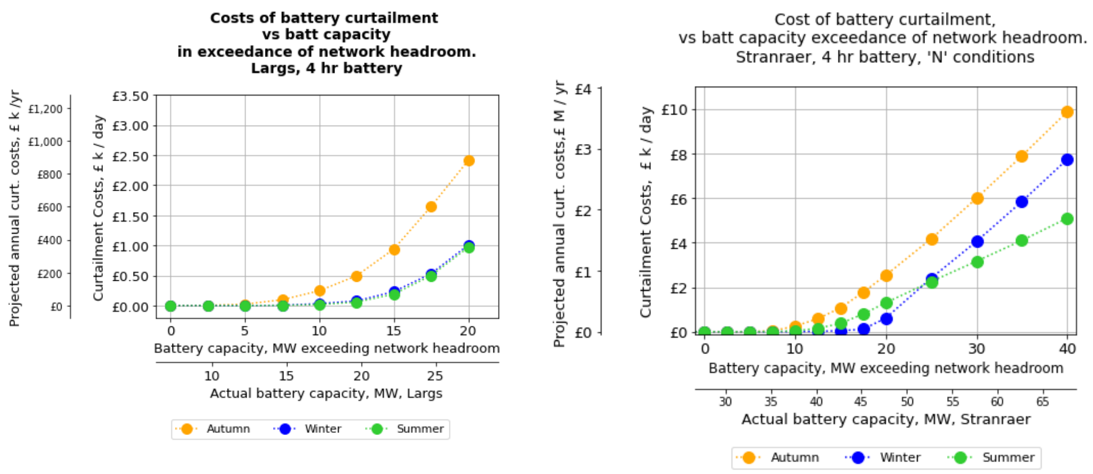


(d)

Figure 97 Average annual battery net revenues PER MW of battery capacity, vs battery capacity. (a): Fairlie, Largs and Lochan Moor, 4hr battery (daily revenues); (b) Armadale, Stranraer and Stevenston, 4hr battery (daily revenues) (c): Fairlie, Largs and Lochan Moor, 4hr battery (annual revenues); (d) Armadale, Stranraer and Stevenston, 4hr battery (annual revenues)

7.4.2. The cost of curtailment (normal "N" conditions)

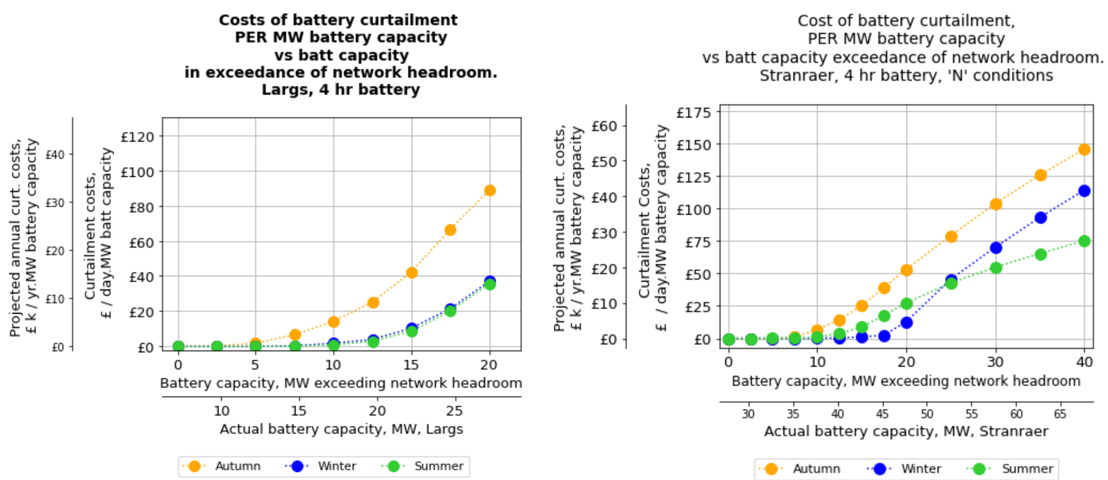
The cost of curtailment, as described earlier, is the difference in battery overall net revenues under unconstrained conditions, and when connected to a constrained network.



(a) Largs (b) Stranraer

Figure 98 Costs of curtailment vs battery capacity, all seasons, 4-hour batteries, Largs and Stranraer ("N" conditions)

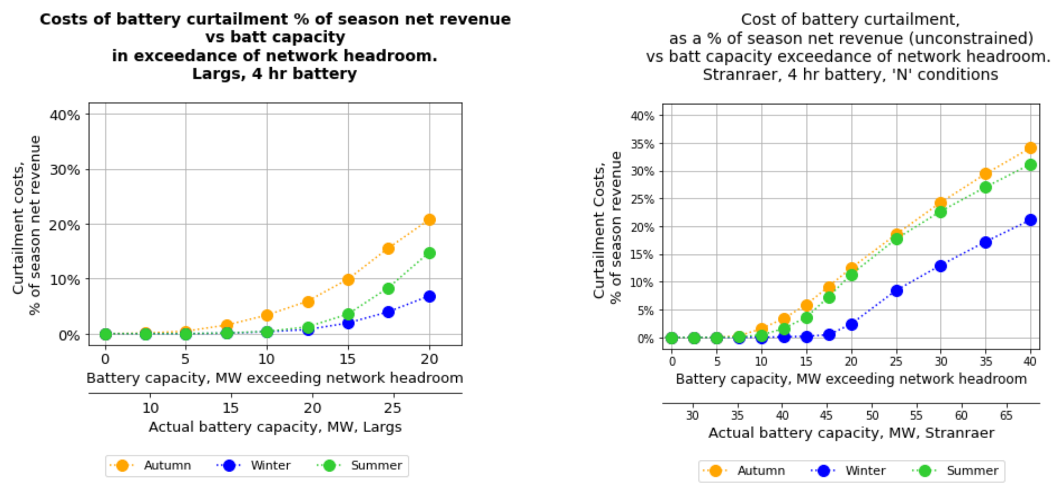
Figure 98 shows absolute costs of curtailment, for each case study season, at Largs and Stranraer. Figure 99 shows cost of curtailment per MW of battery capacity, for the same locations and battery durations, with fuller results shown in Chapter 7 Annex 3.



(a) Largs (b) Stranraer

Figure 99 Costs of curtailment per MW of battery capacity vs battery capacity, all seasons, 4-hour batteries, Largs and Stranraer ("N" conditions)

Both charts show that batteries sized by a small exceedance of network headroom (around 5 MW in the case of single-circuit branch Largs, around 10 MW in the case of 2-circuit branch Stranraer) experience negligible costs of curtailment. Further increase in battery size results in marked increase in costs. Season has a strong effect, with curtailment beginning at smaller battery sizes in autumn than the other seasons. Figure 100 displays curtailment cost, for each season and battery size, as a percentage of the overall revenue the same battery would accrue that season in the absence of network constraints. These locations have instances of costs exceeding 20%, even 30%, for the largest batteries, depending on season, with autumn having highest proportional as well as absolute costs. Relatively high proportional curtailment costs also occur in summer, relative to overall net revenues on unconstrained networks, when such overall net revenues were low.



(a) Largs (b) Stranraer

Figure 100 Costs of curtailment, as a percentage of net revenue without network constraints, for the applicable season, vs battery capacity. 4-hour batteries, Largs and Stranraer ("N" conditions)

Broadly similar results for curtailment costs occurred at all locations.

Viewing year-averaged curtailment costs, the largest batteries modelled had average daily curtailment costs of £1,000 to £10,000/ day, depending on location and battery duration. Full results are appended in Chapter 7 Annex 3.

Figure 101 shows average annual curtailment costs, as a percentage of average annual overall net revenue in the absence of any network constraints, for each location.

These charts show that batteries can be significantly oversized, compared to network headroom, by up to around 10 – 20 MW, and yet incur relatively small proportional curtailment costs: curtailment costs at such battery sizes were typically around 5% of the overall revenue they would accrue on an unconstrained network. However the largest battery sizes modelled would have average curtailment costs of up to between 10% and 35% of their average overall net revenues.

4-hour batteries incurred higher proportional as well as absolute curtailment costs compared to 2-hour batteries of the same (MW) capacity; the 2-feeder case study locations (Armadale, Stranraer and Stevenston) were able to tolerate greater size of battery, without curtailment, than the single-feeder locations (Fairlie, Largs and Lochan Moor).

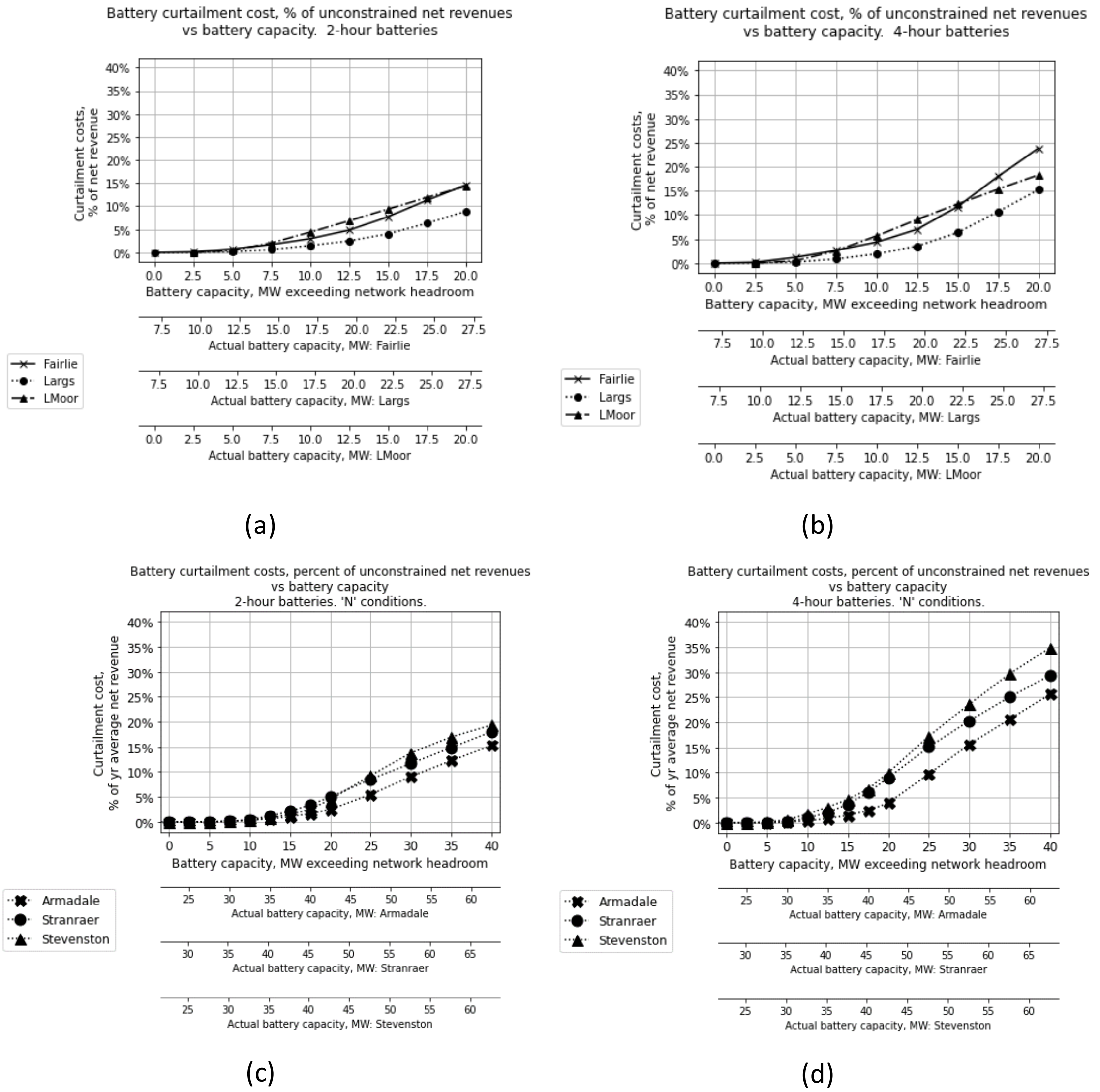


Figure 101 Average battery curtailment costs, as a percentage of year-average net revenues (without any constraints), vs battery capacity. (a) Fairlie, Largs and Lochan Moor, 2-hr batteries, (b) Fairlie, Largs and Lochan Moor, 4-hr batteries; (c) Armadale, Stranraer and Stevenston, 2-hr batteries, (d) Armadale, Stranraer and Stevenston, 4-hr batteries

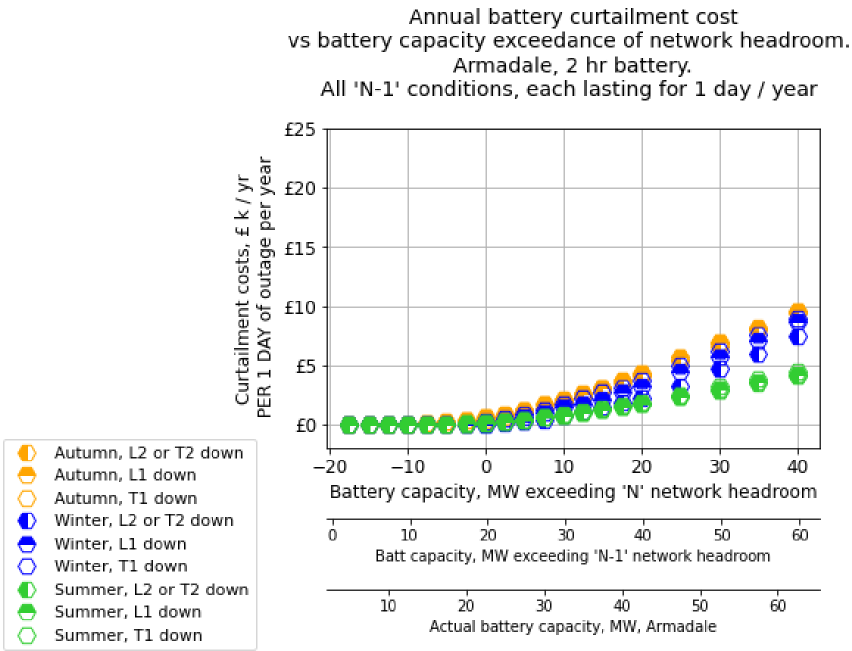
This concludes the results for battery revenues and curtailment costs under normal network operating conditions. The following section, Section 7.4.3, considers battery curtailment under abnormal operating conditions, for the three 2-feeder locations. The section after that, Section 7.4.4, considers curtailment costs under both "N" and "N-1" conditions together, to understand the relative magnitude of these costs.

7.4.3. The cost of curtailment under "N-1" conditions. 2-feeder locations (Armadale, Stranraer, Stevenston) only

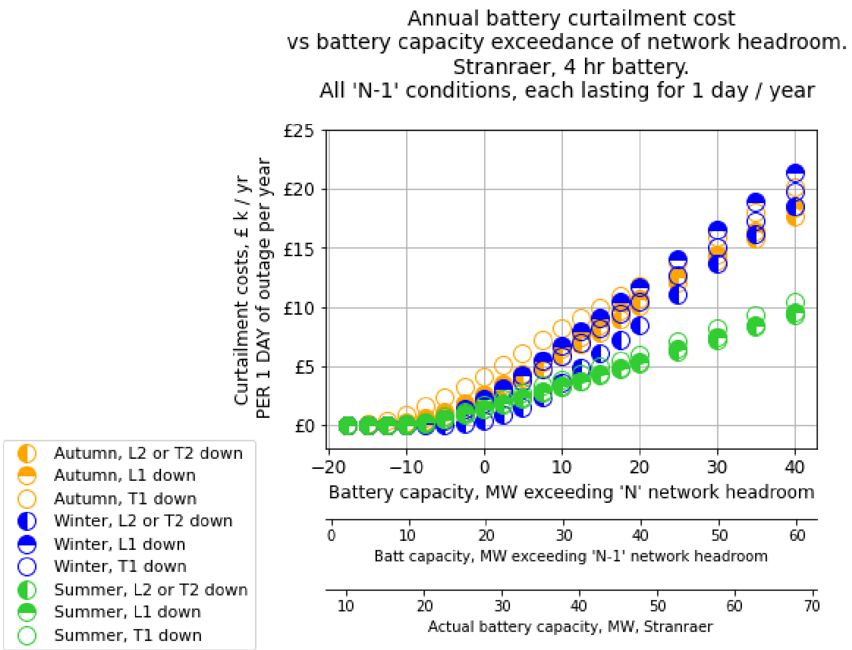
The daily cost of curtailment for each of the two-feeder locations, at each season, for each network condition, was enumerated for the range of battery sizes for each of the three different abnormal network condition scenarios described in Section 7.3.3.3.

Figure 102 shows the cost of 1 day of curtailment, for an "average" day for each season, and for each network condition, at (a) Armadale, 2-hour battery, and (b) Stranraer, 4-hour battery. Full results for the three locations are appended in Chapter 7 Annex 4. The y-axis label "curtailment costs per 1 day of outage per year" mean that these are the total costs that would arise, per day of outage, if the outage fell in the season shown. (The one-day-per-year of outage is later used, together with estimated frequency of outages, to compute actual costs per year from 'N-1' conditions.)

A broadly similar pattern of curtailment cost vs battery size is seen under these "N-1" conditions, as is seen under 'N' conditions (Figure 98). Curtailment costs are initially zero for batteries sized to the available network headroom. An obvious rise in costs begins when batteries are sized around 10-20 MW above prevailing ('N-1') network conditions. This size of battery is approximately 20 MW smaller than that under 'N' conditions, in which almost 20 MW extra network capacity are available. As under 'N' conditions, costs of curtailment varied significantly between seasons, with summer having lower curtailment cost than the other seasons, for most battery sizes. For each season, the costs of the different circuit conditions ('L1 down', 'L2 or T2 down' or 'T1 down') followed a similar pattern. Curtailment costs for 4-hour batteries were roughly double those for 2-hour batteries. Fuller description of these results is given in Chapter 7 Annex 4.



(a) Armadale, 2-hr battery



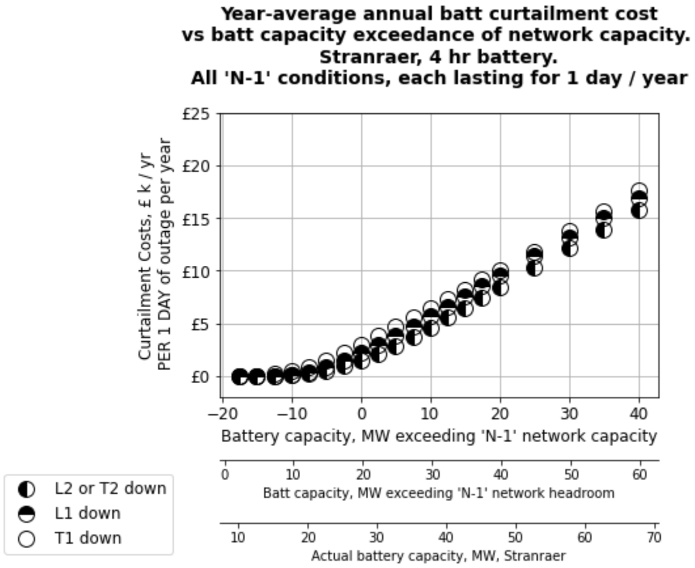
(b) Stranraer, 4-hr battery

Figure 102 Cost of battery curtailment,'N-1' conditions, vs battery size. All seasons, all network conditions: (a) Armadale, 2 hour battery; (b) Stranraer, 4 hour battery

"Year averaged" curtailment costs, across the three seasons, for one day per year of each type of 'N-1' network condition, are displayed in Figure 103 (a), for Stranraer, 4-hour battery. In other words, this chart displays the cost that would arise, on average, for every day of an outage causing the particular ‘N-1’ condition. Full results, for the three locations and both durations of battery are displayed in Chapter 7 Annex 4.

Figure 103 (b) shows the year-averaged *cumulative* annual curtailment cost, for a scenario in which each type of network condition was to occur on one “average” day a year.

(a)
Separate ‘N-1’ conditions



(b)
Cumulative ‘N-1’ conditions

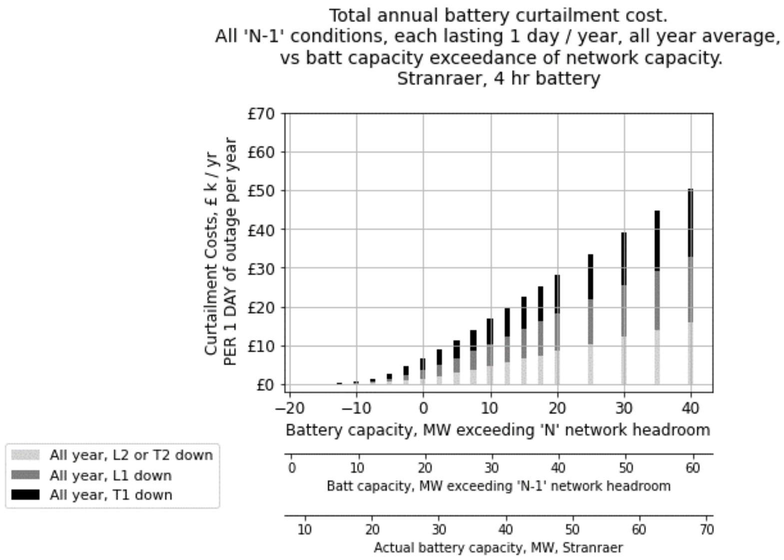
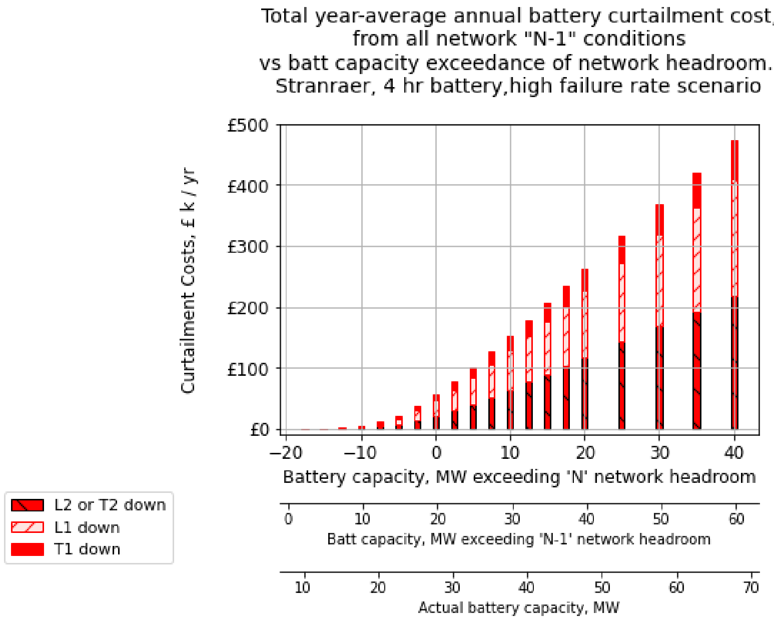


Figure 103 Year-averaged curtailment costs per year vs battery size, all ‘N-1’ conditions, (a) separately) (b) cumulatively, for 1 day per year of each type of ‘N-1’ conditions. Stranraer, 4-hour batteries.

Figure 104 displays the projected year-averaged curtailment costs for Stranraer, and contribution from the three network conditions, in (a) a high failure rate scenario, and (b) a low failure rate scenario, as described in Table 43.

These costs are the product of the daily cost of each type of outage and the projected “no. of days per year” of that outage computed in the chosen scenario (as tabulated in Table 47, Table 48, or Table 49, for low, medium and high failure rate scenarios respectively) to obtain the projected annual cost.

(a)
High failure rate scenario



(b)
Low failure rate scenario

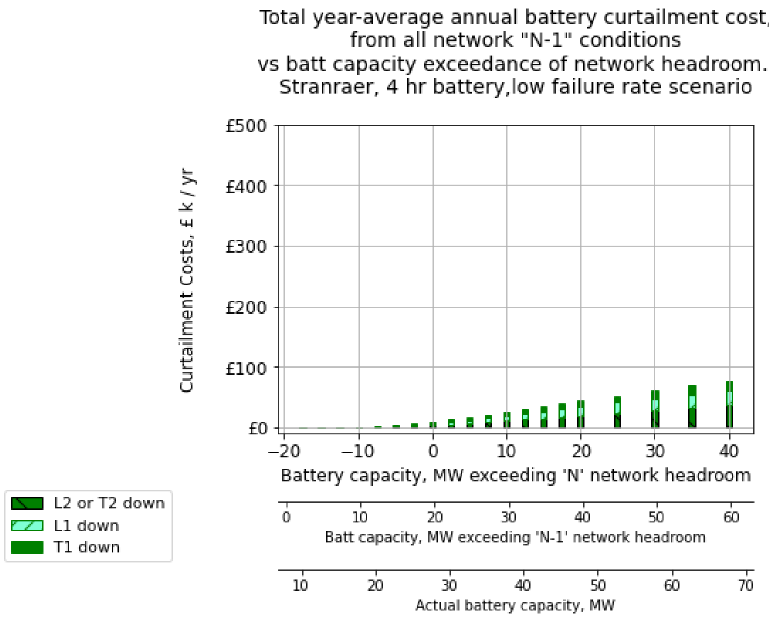


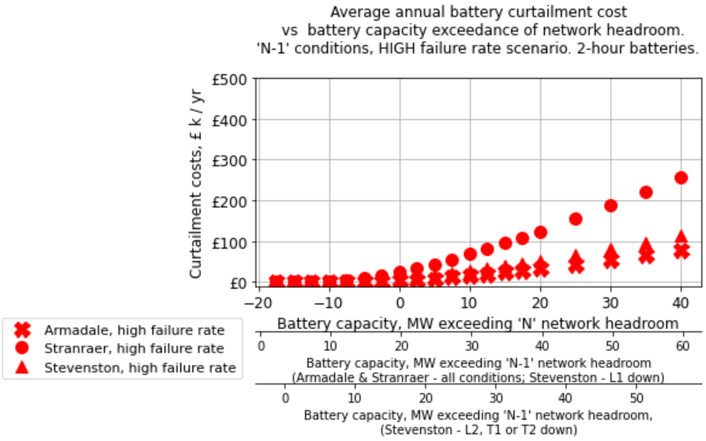
Figure 104 Year-averaged total curtailment costs per year vs battery size, showing contributions from each network condition. (a) high failure rate scenario; (b) low failure rate scenario. Stranraer, 4-hour batteries.

For both failure rate scenarios, the major contribution to cost is from failure in L1 or L2. As shown in Chapter 7 Annex 5, this does not hold for Armadale or Stevenston, which both have much shorter feeders, and thus much lower projected failure rate for each feeder.

Figure 105 shows the projected average annual curtailment cost, for all three locations, under scenarios of a high failure rate (a) and (b) and low failure rate (c) and (d). Curtailment costs for 2-hour batteries are shown in (a) and (c), and for 4-hour batteries in (b) and (d), respectively.

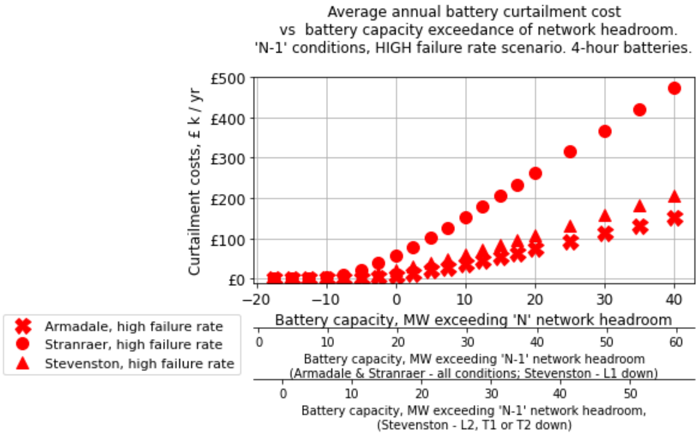
(a) high failure rate,

2-hour batteries



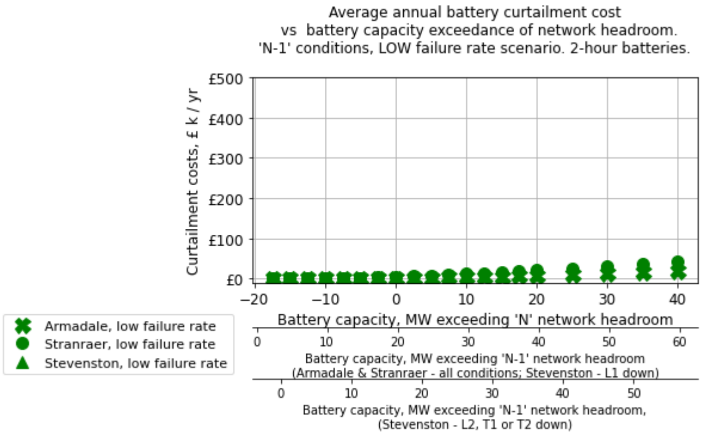
(b) high failure rate,

4-hour batteries



(c) low failure rate,

2-hour batteries



(d) low failure rate,

4-hour batteries

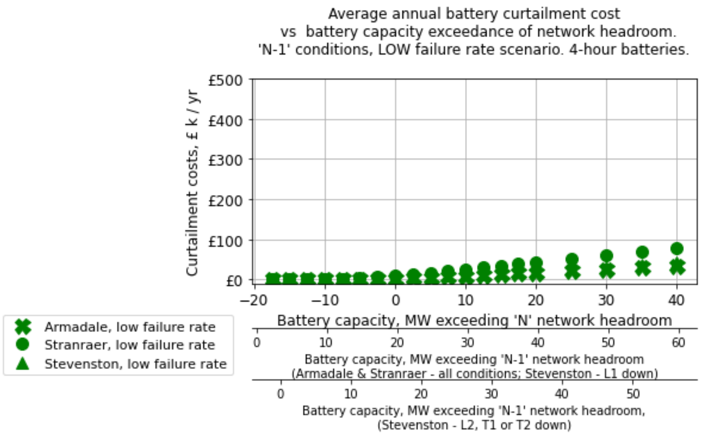


Figure 105 Projected total average annual curtailment costs, of all 'N-1' scenarios, vs battery size. High and low failure rate scenarios. Armadale, Stranraer and Stevenston

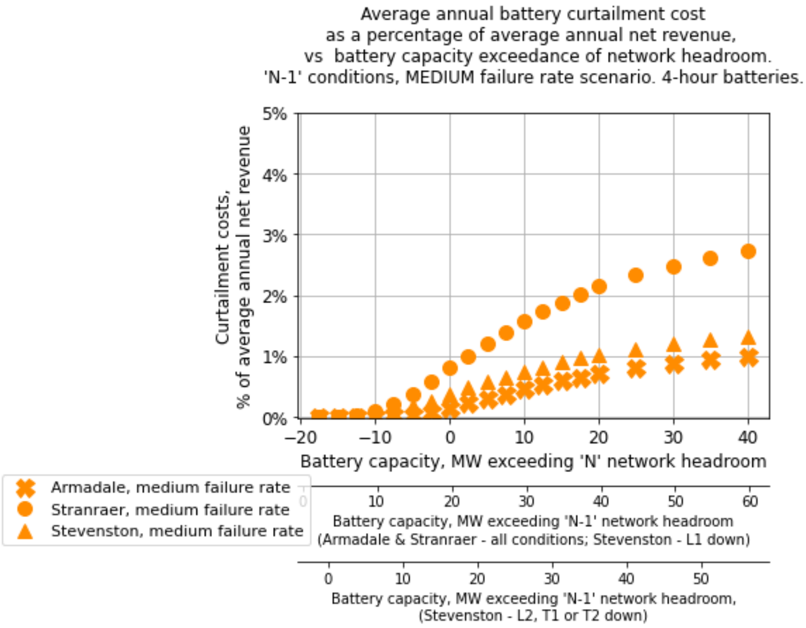
For the biggest batteries modelled, these projected 'N-1' curtailment costs range from £20,000 - £80,000 / year for low failure rate scenario, up to between £100,000 - £500,000 /year for a high failure rate scenario, depending on location and battery duration.

Figure 106 shows the average annual curtailment costs, for the medium and high failure rate scenarios, for the three locations, as a percentage of average annual battery overall net revenue on an unconstrained network, for 4-hour batteries. These charts show that the proportional revenue cost does not exceed 5% of projected average annual net revenue in any scenario; for Armadale and Stevenston, the largest batteries had proportional curtailments costs of up to around 1% of uncurtailed average overall net revenue in a medium failure rate scenario, and up to around 2 % of uncurtailed average overall net revenue in a high failure rate scenario. Fuller results are appended in Chapter 7 Annex 5. Table 52 shows the range of proportional curtailment costs of the largest batteries considered, for all failure rate scenarios.

Table 52 Range of average curtailment costs of all 'N-1' conditions, as a proportion of average overall net revenues of an unconstrained batteries, for batteries oversized by 40 MW in excess of 'N' network headroom. Armadale, Stranraer and Stevenston, all failure rate scenarios

Failure rate scenario	Proportional total curtailment costs of the largest batteries investigated, considering all 'N-1' scenarios, as a proportion of average overall net revenue an unconstrained battery could accrue.	
	2 hour batteries	4 hour batteries
Low	0.3% - 0.6%	0.3 % - 0.8%
Medium	1% - 2%	1% - 3%
High	1% - 4%	2% - 5%

(a) Medium failure rate



(b) High failure rate

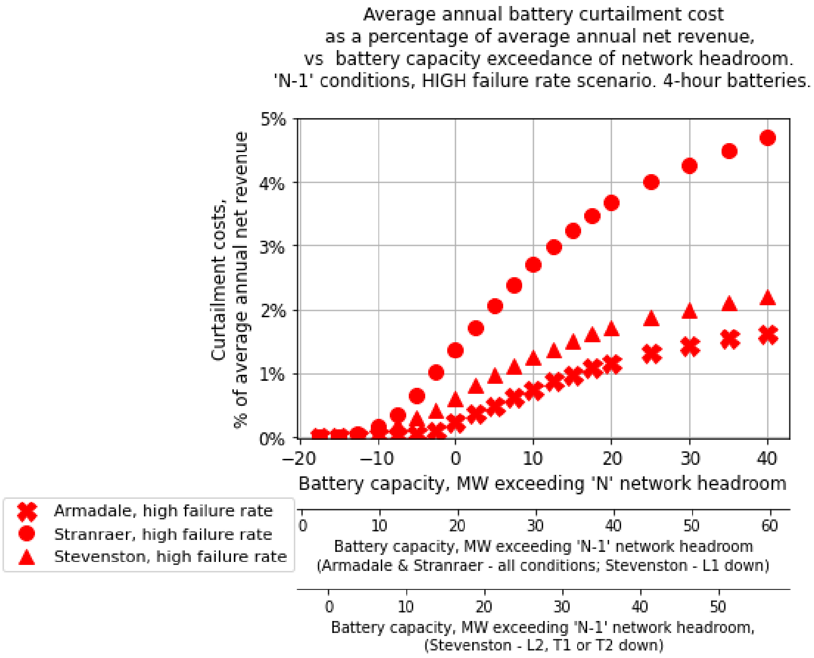


Figure 106 Year-averaged annual curtailment costs, as a percentage of unconstrained average annual net revenue, vs battery size. Armadale, Stranraer and Stevenston, 4-hour batteries (a) medium failure rate scenario; (b) high failure rate scenario

The following section, Section 7.4.4, considers how significant or otherwise these costs are, compared with total annual costs under "N" conditions.

7.4.4. The cost of curtailment, considering ‘N’ and ‘N-1’ conditions together. Armadale, Stranraer and Stevenston

Figure 107 shows the variation of curtailment costs with battery size, for only ‘N’ conditions, and the sum of ‘N’ and ‘N-1’ curtailment costs, under a high failure rate scenario. This chart shows that the additional cost of curtailment under ‘N-1’ conditions is small, compared with costs under ‘N’ conditions, for batteries sized above around 20 MW above ‘N’ network headroom. The cost increment is larger for Stranraer than the other locations. Here, the year-average ‘N’ costs have been slightly reduced, compared to the base case displayed in Chapter 7 Annex 3, Figure 199, to account for ‘N’ conditions not occurring on days when ‘N-1’ conditions occur.

Figure 108 shows the ‘N’ and ‘N-1’ costs, separately, and in greater detail, for batteries sized up to 20 MW above ‘N’ network headroom, for a high failure rate scenario.

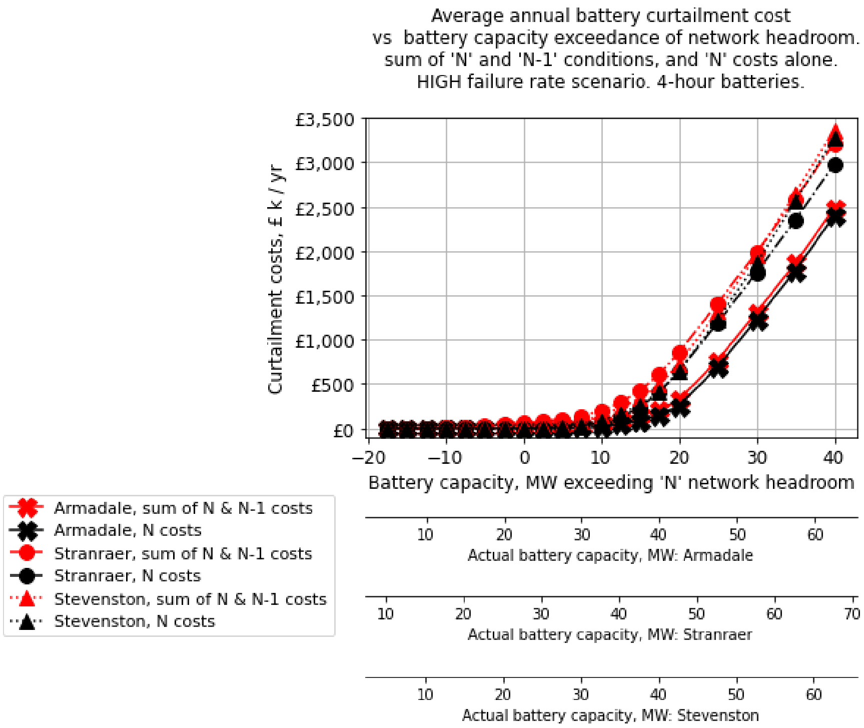


Figure 107 Average annual curtailment costs, all battery sizes, high failure rate scenario. ‘N’ conditions alone, and the sum of ‘N’ and ‘N-1’ costs. Armadale, Stranraer and Stevenston, 4-hour batteries.

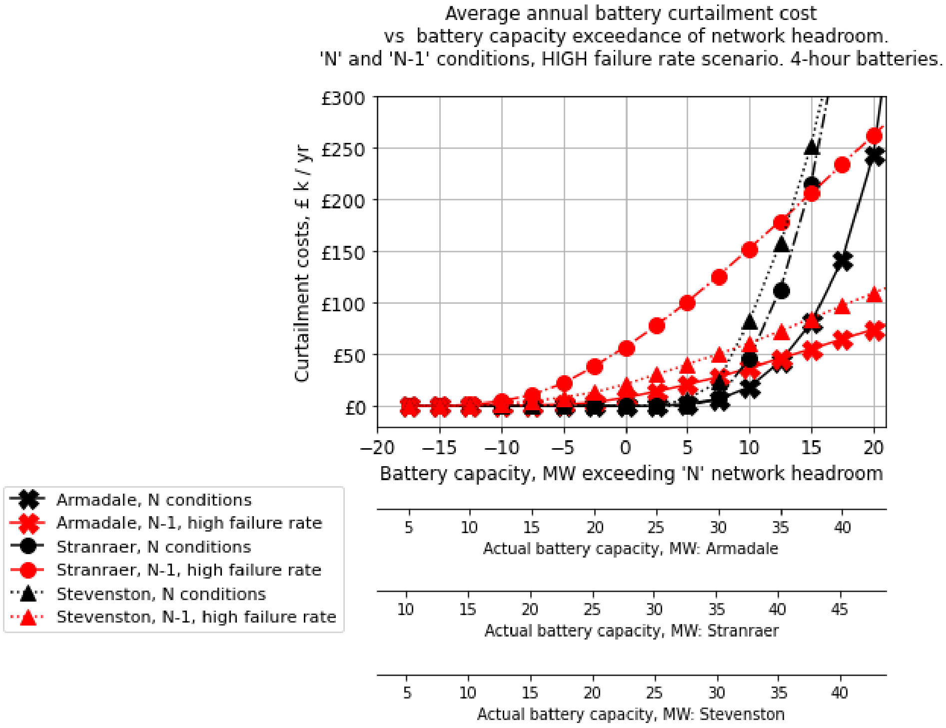


Figure 108 Average annual curtailment costs, battery sizes up to 20 MW above 'N' network headroom, high failure rate scenario. Costs under 'N' and 'N-1' conditions. Armadale, Stranraer and Stevenston, 4-hour batteries.

Figure 108 shows that small 'N-1' costs occur for batteries sized 0 to 10 MW *below* 'N' network headroom, sizes at which 'N' curtailment costs are zero. The 'N-1' costs dominate the overall curtailment costs for batteries sized up to around 5 - 15 MW above 'N' network headroom, depending on location. The 'N-1' costs are much more significant for Stranraer than for Armadale or Stevenston. However, even here, these 'N-1' curtailment costs are relatively small – up to ~ £200,000 per year for a battery sized 15 MW above network headroom, compared to projected average annual overall net revenues of over £6 M for a battery of this size.

Similar results are obtained for 2-hour batteries, and for 2-hour and 4-hour batteries under a medium failure rate scenario. 'N-1' costs under low failure rate scenarios were small. All results are documented in Chapter 7 Annex 6.

7.5. Discussion

7.5.1. A "network headroom" approach to displaying curtailment costs allows for comparison of different sites.

This work seeks to find if generic lessons can be learned which might be applicable to other locations. Thus, a "harmonised" approach to battery sizing, relative to conditions of individual network locations, allows results from multiple locations to be presented together. This approach helps see if every location is truly an individual case, or whether there are any generic results, obtained across most or all of the locations studied, and which might suggest likely behaviour at other sites.

To a first approximation, all the sites investigated exhibited similar behaviour:

- Initially: no significant curtailment cost, for batteries sized up to a small excess of network headroom (around ~5-10 MW in several cases);
- Small but slowly increasing curtailment costs as battery size increased from there up to a larger excess of network headroom (around ~10-20 MW in several cases);
- thereafter, further increases in battery size caused a steady and significant increase in curtailment costs.

This general pattern was seen across all six sites, despite large differences in the degree of penetration of wind generation. Comparing the three single-feeder sites with one another, and the three two-feeder sites with one another, net battery revenues per MW of battery capacity began to fall, and costs of curtailment began to rise, at similar "battery sizes in excess of network headroom". This demonstrates that the "network headroom" approach – despite not being an exact science – is useful in allowing comparisons of different sites.

7.5.2. Curtailment costs are strongly dependent on battery capacity

The pattern of curtailment costs vs battery capacity in excess of network headroom is broadly similar at all locations and for both battery durations, as previously shown in Figure 98 - Figure 101, and in Annex 3.

- Zero curtailment costs – for battery sizes of no or little exceedance of network headroom
- Curtailment costs which are low and increase slowly – for increasing battery sizes

- Curtailment costs which are higher and which rise more steeply with battery size – for the largest battery sizes. In some cases the increase in curtailment costs with increasing battery size was approximately linear.

Defining “knee points” between these regions was challenging for several reasons. Firstly, the shapes of the curves varied a little according to whether costs were portrayed as “costs (£) vs battery size (MW)”, or as “costs per MW of battery capacity (£/battery MW) vs battery size (MW)”, or as “costs as a percentage of overall net revenues vs battery size (MW)”. Also, the apparent position of knee points themselves sometimes differed according to the scale chosen for the graph. Furthermore, as previously described, these annual curtailment costs are themselves weighted average costs of those for each of the three seasons. Figure 98 - Figure 100 show that for Largs and Stranraer the rise in costs (per MW of battery size) with battery size began for smaller batteries in autumn than in the other seasons, an observation which also is seen in the other locations, as shown in Chapter 7 Annex 3.

Thus, a pragmatic definition to delimit regions of “low curtailment costs” and “higher curtailment costs” was adopted, based on curtailment cost as a proportion to overall net revenue. A level of average annual curtailment cost of up to 5% of annual net revenue was defined as being “low”; average annual curtailment costs above 5% of annual net revenues were defined as “higher”. This level is also intended to represent a level at or above which costs increase significantly with increasing battery size.

The regions of “low curtailment costs” and “higher curtailment costs” are shown in Figure 109, for 4-hr batteries at Armadale, Stranraer and Stevenston. (This graph is an annotated copy of part of Figure 101.)

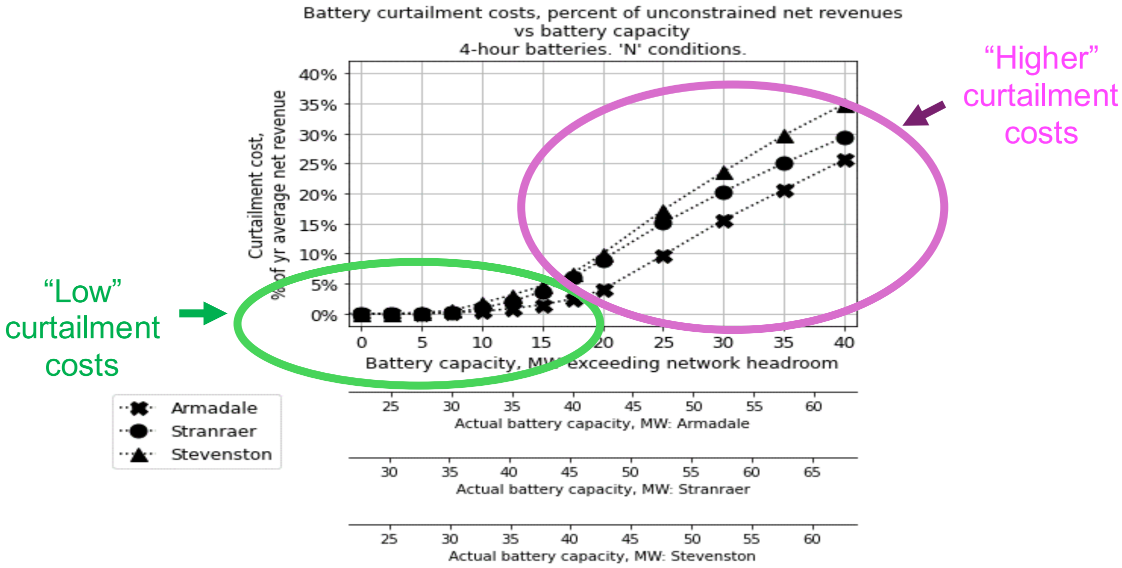


Figure 109 Battery curtailment costs vs battery capacity: "low" and "higher" curtailment costs areas

Table 53 lists the maximum size of battery for a "low" curtailment cost at each location, as defined above. This shows broadly similar battery sizes, among the three locations of the same circuit type, for batteries of the same duration.

Table 53 Battery size, in excess of network headroom, causing an annual average curtailment cost of 5% of unconstrained average overall net revenue. All locations, 2 hour and 4 hour batteries.

Network type	Location	Battery capacity in excess of network headroom, causing 5% annual average curtailment costs ("N" conditions only)	
		2 hour batteries	4 hour batteries
Single feeder	Fairlie	13 MW	11 MW
	Largs	16 MW	14 MW
	Lochan Moor	10 MW	9 MW
Two feeders	Armadale	25 MW	21 MW
	Stranraer	20 MW	17 MW
	Stevenston	21 MW	16 MW

In many locations, around this respective battery size, the pattern of curtailment cost vs battery size changes from an initially slow but increasing rate, to a more linear increase with increasing battery size. (Figure 101 in Section 7.4.2 previously showed proportional curtailment costs for all locations and both battery durations, and full results are appended in Chapter 7 Annex 3.)

7.5.2.1. “Low” curtailment costs region of Figure 109

This section explores why batteries can be oversized *at all*, let alone by up to around 10-20 MW, compared to network headroom, and yet still have relatively low curtailment costs.

The following possible explanations are proposed:

- Hypothesis 1: The battery actions are *never or only rarely curtailed*. Battery trades fit well with the needs of the network, and do not add to network congestion
- Hypothesis 2: The battery actions *are curtailed*, but these curtailment events *have little cost impact*.

To investigate which explanation might occur, an analysis of the timeseries of battery actions was undertaken, for two sizes of battery for each location. Sizes were selected to have “*minimal*” average annual curtailment costs of around 1% and around 2% of unconstrained average overall net revenues; termed “smaller” and “larger” respectively. The chart of proportional average annual curtailment costs vs battery size is previously plotted in Figure 101 in Section 7.4.2. Table 54 shows the battery sizes used in this analysis. The same battery sizes were used for 2-hour and 4-hour batteries at each location.

Table 54 Battery trades analysis. Sizes of “smaller” and “larger” batteries at each location

<table>
<tr><th rowspan="2">Location</th><th rowspan="2">Number of feeders</th><th colspan="2">Battery size in excess of network headroom (“N” conditions)</th></tr>
<tr><th>“Smaller” batteries</th><th>“Larger” batteries</th></tr>
<tr><td>Fairlie</td><td rowspan="3">1</td><td rowspan="3">5 MW</td><td rowspan="3">7.5 MW</td></tr>
<tr><td>Largs</td></tr>
<tr><td>Lochan Moor</td></tr>
<tr><td>Armadale</td><td rowspan="3">2</td><td rowspan="3">10 MW</td><td rowspan="3">15 MW</td></tr>
<tr><td>Stranraer</td></tr>
<tr><td>Stevenston</td></tr>
</table>

Actual annual average curtailment costs for batteries of these sizes are shown in Chapter 7 Annex 7.

Definitions of battery events

The analysis requires a definition of the *types* of battery events. There are possible 8 types of events, from all combinations of: -

- import / export
- “completed” / “not completed”
- “unconstrained” / “network constrained”

All battery “events” normally occurred over multiple timesteps. Table 55 defines an “import event” and an “export event”, in both cases “completed” and “not completed”. Table 56 defines “unconstrained” and “network constrained” import and export events, completed and not.

In all cases (locations, seasons, selected battery sizes), the timeseries of all battery trades were analysed, with all battery actions categorised into the 8 categories in the above bullets (and shown in Table 56. The logic used for the categorisation is appended in Chapter 7 Annex 8.

Full results are tabulated in Chapter 7 Annex 9, and plotted in Chapter 7 Annex 10. Selected results are described below.

Table 55 Definition of battery "import" and "export" events

Type of event	Previous event	Battery SOC after import / export event	Classification
Import	Export	1 (nominally)	Unique import event: completed
Import	Export	< 1 (nominally)	Unique import event: NOT completed
Import	Import	Any	Part of an import event counted elsewhere
Export	Import	0 (nominally)	Unique export event: completed
Export	Import	> 0 (nominally)	Unique export event: NOT completed
Export	Export	any	Part of an export event counted elsewhere

Table 56 Definitions of unconstrained and network-constrained battery imports and exports, completed and not completed

Type of event	Network constraints?	Power flow rate of battery	Import / export	Import / export event completion	SOC of battery following the event	Example
Unconstrained import: completed	No	Full, during all timesteps, (unless limited by battery SOC)	Import	Completed	1 (nominally)	Unhindered battery import
Unconstrained import: NOT completed		Full	Import	Not completed	< 1 (nominally)	Price pattern becomes unfavourable for import
Unconstrained export: completed		Full, during all timesteps, (unless limited by battery SOC)	Export	Completed	0 (nominally)	Unhindered battery export
Unconstrained export: NOT completed		Full	Export	Not completed	> 0 (nominally)	Price pattern becomes unfavourable for export
Network-constrained import: completed	Yes	**< full power, because of network constraints,** during some or all timesteps	Import	Completed	1 (nominally)	Battery imports, at reduced power, until fully charged
Network- constrained import: NOT completed			Import	Not completed	< 1 (nominally)	Battery starts to export before SOC reaches 1
Network- constrained export: completed			Export	Completed	0 (nominally)	Battery exports, at reduced power, until fully discharged
Network- constrained export: NOT completed			Export	Not completed	> 0 (nominally)	Battery starts to import before SOC reaches 0

Examples of hypothesis 1: Battery actions never or rarely curtailed

Figure 110, showing categorisation of battery trades in winter, for "smaller", 2-hour batteries, is an example of most locations not having curtailment at all. The upper chart categorises the battery's import trades. Not surprisingly, in export-dominated Fairlie, Largs, Lochan Moor and Armadale, none of the imports is affected by network constraints. This also applies to Stranraer. The middle box shows categorisation of exports. Here, there are no network-constrained export trades at Largs, Lochan Moor or Armadale, and of course none at demand-only Stevenston. Stranraer and Fairlie have only 2 and 6 network-affected exports during the season, respectively, out of a total of 42 export actions in both places. The bottom chart displays the cost of the curtailment, as a percentage of the season's overall net revenue for an unconstrained battery. Even at Fairlie, where 1 in 7 trades was affected by network constraints, the financial impact was minimal – well under 1% of season's overall net revenue.

The results for Stevenston are discussed under "hypothesis 2".

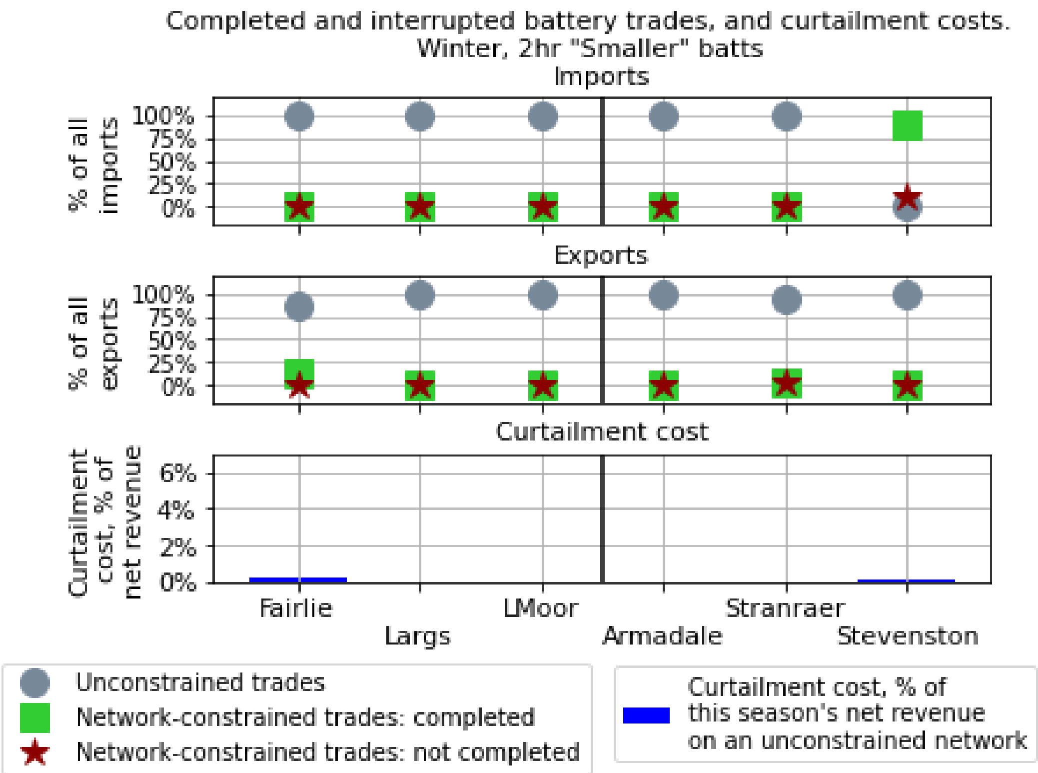


Figure 110 Categorisation of battery trades, and curtailment costs. Winter, "smaller" batteries, 2-hour duration, all locations.

Hypothesis 2: Battery actions curtailed, but with little financial impact

Figure 111 shows categorisation of battery trades, and curtailment costs, during autumn, for the same sized batteries as those described above.

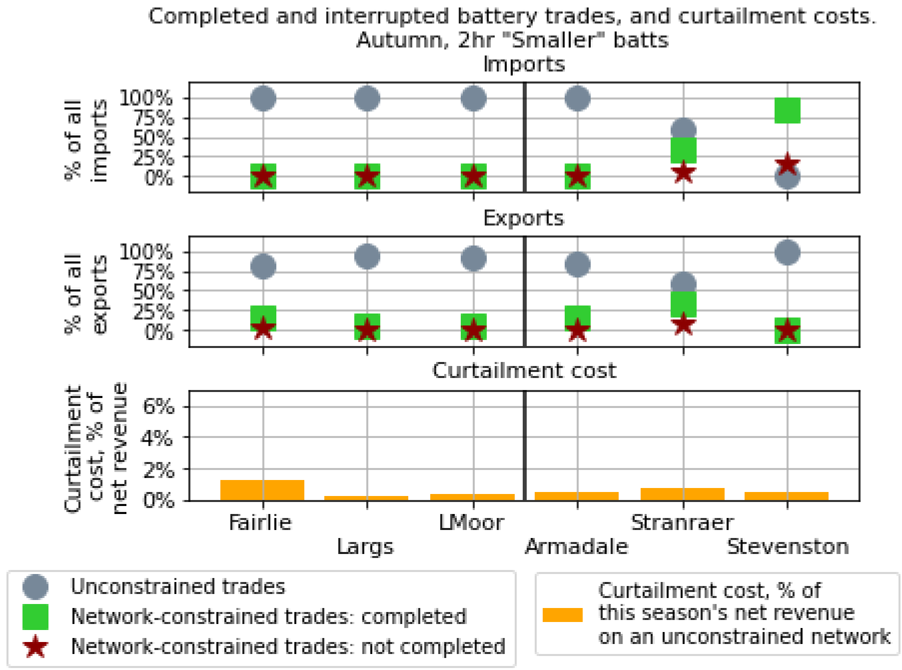


Figure 111 Categorisation of battery trades, and curtailment costs. Autumn, "smaller" batteries, 2-hour duration, all locations.

Considering the windier conditions in autumn compared to the winter case study period, it is not surprising that all locations apart from demand-only Stevenston have some export trades affected by network constraints: between 4 (in Largs) and 31 (in Stranraer) of the 76 export trades were limited by network limits. Furthermore, all of the import trades at Stevenston, and 40% of Stranraer's import trades were also constrained by network limits. However, curtailment costs were very low, the highest being a little over 1% of unconstrained net revenue for the season.

A closer inspection of Figure 111 helps explain this apparent paradox. The majority of all trades affected by network constraints actually went to completion, i.e. most import trades continued until the battery was fully charged, and most export trades continued until the battery was fully discharged. Thus the battery completed most of the trade cycles it would have done on an unconstrained network (in some cases requiring additional timesteps to do so), and the impact on its overall revenue was minimal. Very similar results were found at Stevenston in winter, as shown in the previous chart, Figure 110.

The slightly larger batteries, in autumn, have a similar pattern, as shown in Figure 112. Far more export trades are affected by network limits compared to the previous example with “smaller batteries. Around 25% of exports at Fairlie, Largs, Lochan Moor and Armadale, and around 80% of Stranraer’s exports are limited by network limits; import trades are also constrained at Armadale (over a third of trades), Stranraer(over 80% of trades) and Stevenston (all trades). Nevertheless, curtailment costs were under 4% of unconstrained net revenues at all locations. Again, inspection of Figure 112 shows that the majority of the network-limited trades, both imports and exports, continued to completion.

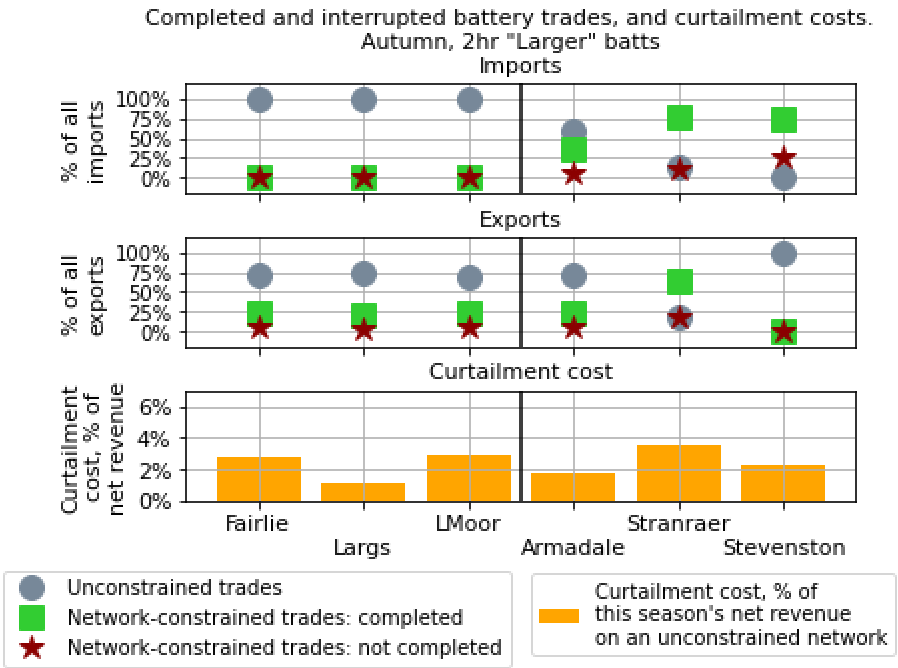


Figure 112 Categorisation of battery trades, and curtailment costs. Autumn, “larger” batteries, 2-hour duration, all locations.

Inspection of timeseries of network and simulated battery flows is also useful to understand the results. Figure 113, similar to those shown previously in Chapter 6 Annex 11 and Chapter 6 Annex 12, shows timeseries flows at Armadale, for a 2 hour battery sized 15 MW above network headroom (as shown in Table 42). In this chart, battery flows (green), superimposed on overall network flows (blue), at times exceed both import “N” network limits (horizontal black dashed line, above zero) and at other times exceed export “N” network limits (horizontal black dashed line, below zero). However, the degree of curtailment is small, (up to ~ 5 MW for imports and occasionally ~ 10 MW for exports) and normally one additional timestep is enough time to complete the intended trade. This illustrates why Figure 112 above shows that a 2-hour battery of this size located at Armadale, though having significant numbers of its import and export trades curtailed, almost all trades go to completion, and the impact on cashflows is low: under 2% of seasonal overall net revenues.

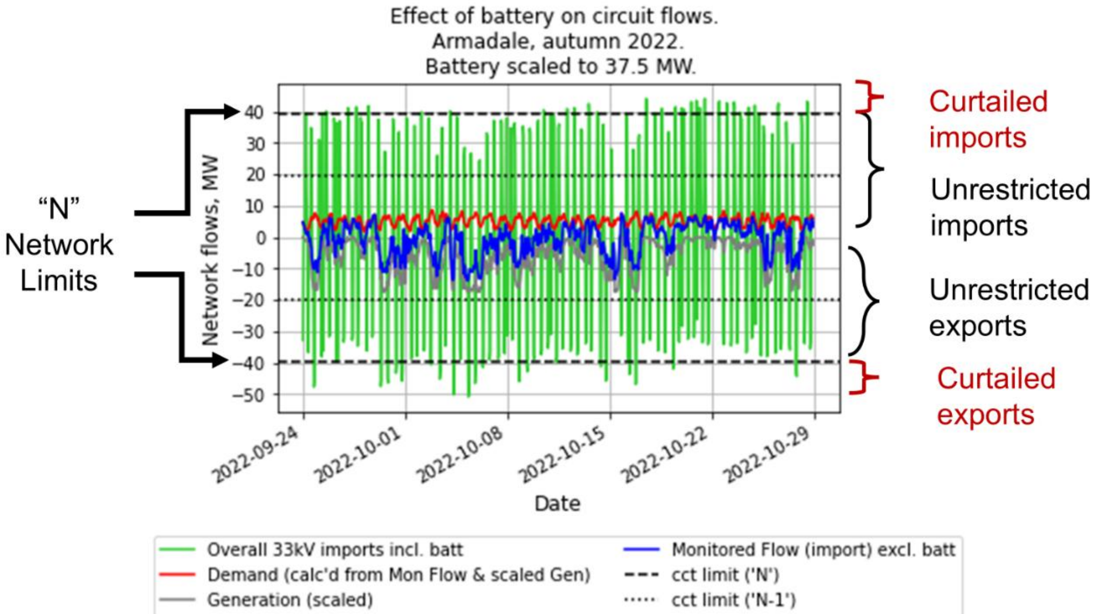


Figure 113 Timeseries network and simulated battery flows at Armadale, autumn. 2hr battery, 15 MW in excess of network headroom under 'N' conditions (37.5 MW). Showing unrestricted and curtailed imports and exports. Small degree of curtailment.

This is an example of a "win-win" situation: a battery operator can operate larger batteries than would be possible with a firm connection; the network operator can curtail the battery action when necessary to manage flows within network limits, but costs of curtailment to a battery owner would be low.

7.5.2.2. "Higher" curtailment costs region of Figure 109

For batteries of capacity around 20 MW above network headroom (2-feeder locations) / 10-12 MW above network headroom (single feeder locations), curtailment costs increase more steeply with increasing battery capacity.

Figure 114 shows the timeseries of demand and battery flows at Stevenston, similar to charts previously shown in Chapter 6 Annex 11. As in Figure 113, this is in autumn, for a 2-hour battery. This one is sized here sized at 25 MW above network headroom.

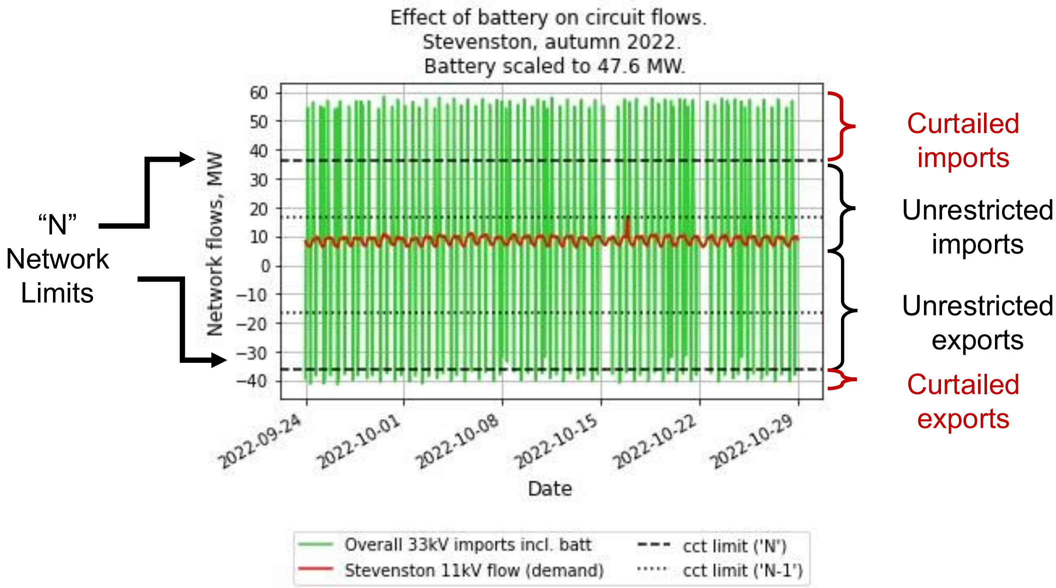


Figure 114 Timeseries network and simulated battery flows at Stevenston, autumn. 2hr battery, 25 MW in excess of network headroom (47.6 MW). Showing unrestricted battery trades would breach network import and export limits twice most days.

This chart illustrates that every single import flow is significantly curtailed. An import action normally requiring 2 to 3 hours would, under such network restrictions require approaching 100% longer, around 4 hours. On any occasions when low prices do not persists for this duration, imports are likely to be interrupted. Further increases in battery size (MW) will exacerbate this problem, and increasing share of battery capacity will rarely be cycled, and thus redundant for some trades. This effect is far more pronounced for 4-hour batteries, as discussed below in Section 7.5.4.

Nevertheless, additional battery capacity, even when very oversized compared to network capacity, does accrue additional revenue, at all locations and battery sizes simulated, as illustrated in Figure 95 - Figure 97, though financial returns diminish with additional battery capacity.

A battery owner may indeed choose to oversize batteries, in the expectation battery degradation leading to reduction in battery MW capacity and / or duration during the lifetime of the assets. This analysis shows that the oversized battery capacity, while not as financially productive as it would be on a less constrained network, can still accrue additional revenue for its owner. Depending on the business model and expected degradation pattern, such oversizing may be a viable option.

7.5.3. Curtailment costs vary significantly with seasons.

Figure 98, Figure 99 and Figure 100 show examples of costs of curtailment at different season, for Largs and Stranraer; results for all locations are contained in Chapter 7 Annex 3. These show significant differences in curtailment costs between seasons, with curtailment costs generally being higher in autumn, at all locations and for most battery sizes.

There are several different factors affecting network flows and battery curtailment.

OHL Thermal ratings

During winter, most of the OHLs had wider thermal ratings, than during the other seasons, allowing higher flows. This increase in network capacity contributed to reduced curtailment during winter.

Demands

At all locations, demands were higher in winter, and lower in summer, except at Fairlie, where demand was so small there was little noticeable seasonal variation.

For the wind-dominated locations, the higher demand in winter reduced export flows. This effect reduced export flows at most sites during the winter case study season. At Fairlie, because of its small demand, a modestly-sized battery would have higher curtailment cost than at other sites during winter (as described in Figure 110 in Section 7.5.2), though such costs are still low. Conversely, during summer months, during periods of high wind, the lower demand flows – especially at Lochan Moor, resulted in relatively high export flows at those times.

Windfarm outputs

There were periods of windy weather during all the case study seasons, but autumn was the season with longest periods of windy conditions, and the highest values of wind outputs. This contributed to the greater curtailment cost during autumn than during other seasons, at the wind-dominated sites. Lochan Moor had particularly high outputs during some of the summer case study period too. However, this factor alone does not explain all the differences in curtailment costs between seasons, especially at Stevenston which has no wind generation at all.

Price pattern, and its alignment or misalignment with network flows

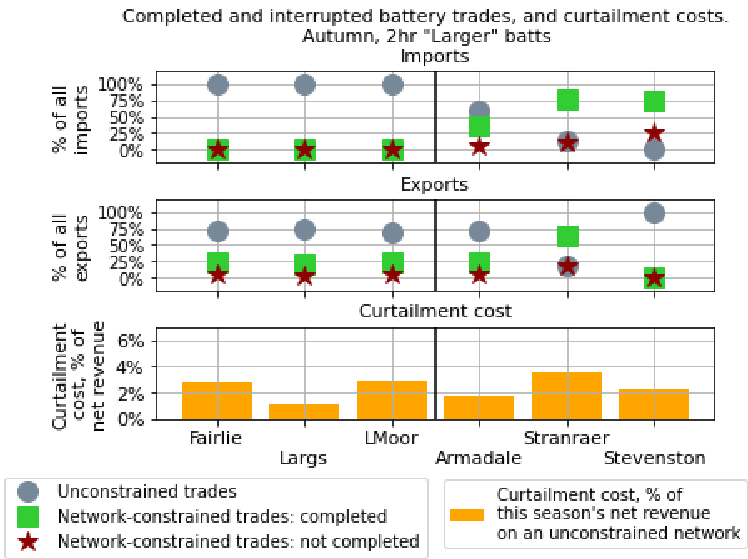
None of the above factors explain demand-only site Stevenston's higher curtailment costs during the autumn season than in winter, as shown in Chapter 7 Annex 3 Figure 197, when overall demands were higher. Chapter 7 Annex 3 Figure 198 shows that proportional curtailment costs, compared to an unconstrained battery's overall net revenue, were even higher during summer at Stevenston than in winter. Examination of the pricing pattern is necessary to understand why this has happened. As previously discussed in Chapter 6, Figure 77 shows that the battery is incentivised to trade twice a day, exporting during both morning and evening price peaks, and importing both at night and also around midday. This pattern of battery trades – incentivised by the wholesale price pattern - fits poorly with the network flows at Stevenston, where there is virtually no midday reduction in import flows. Thus, battery imports around midday exacerbate already high daytime import flows on the network. During summer, broadly similar price pattern to that in autumn occurred on most days, encouraging similar battery behaviour,

However, different behaviour is seen in winter, as shown previously in Figure 76 of Chapter 6. During the cold calm spell in the middle of the case study period, the battery trading behaviour – incentivised by the wholesale price patter – aligned well the network flows at Stevenston, and tended to reduce overall network flows. This price pattern alignment is part of the reason for relatively low curtailment costs in winter compared to other seasons. Similar behaviour is also seen at other sites which have significant demand.

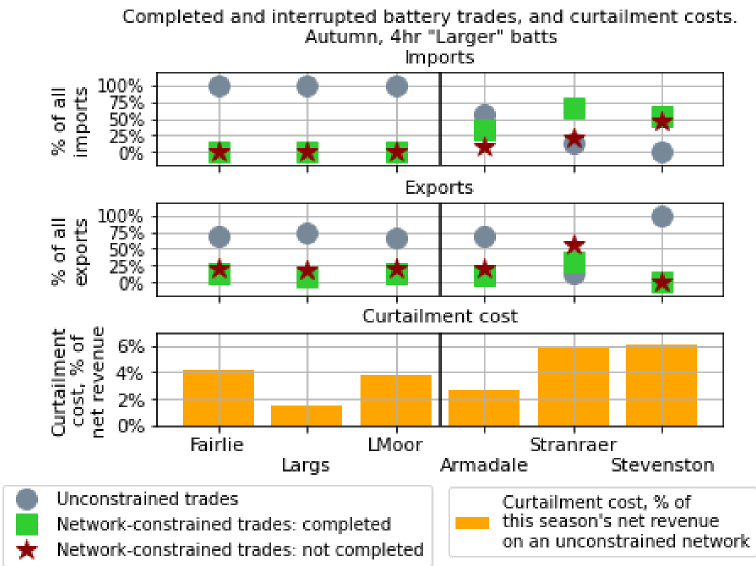
7.5.4. Curtailment costs vary significantly with battery duration

Figure 101, and Figure 198 and Figure 201 in Chapter 7 Annex 3, show that year-averaged proportional curtailment costs are significantly higher at all sites for 4-hour batteries than 2-hour batteries of the same capacities. Figure 197 and Figure 199 of Chapter 7 Annex 3 show that *absolute* curtailment costs for 4-hour batteries, are around double those of 2-hour batteries, for most sites and battery sizes.

To understand why battery duration has such a significant effect on curtailment costs, examination of the analysis of battery trades, described above, is used.



(a) 2-hour battery



(b) 4-hour battery

Figure 115 Categorisation of battery trades, and curtailment costs. Autumn, (a) 2-hour battery; (b) 4-hour battery. "Larger" batteries (Fairlie, Largs, Lochan Moor: 7.5 MW above network headroom; Armadale, Stranraer, Stevenston: 15 MW above network headroom).

Figure 115 (a), depicting 2-hour batteries, shows that, while a significant number of export trades are affected by network limits, at all locations except for Stevenston, in all cases, most of the export trades affected by network limits nevertheless were completed.

However, Figure 115 (b), depicting 4-hour batteries, shows that at all those 5 sites, most of the network-limited exports did were not completed. At Stevenston, a similar effect was seen regarding import trades, all of which were limited by network constraints. With 2-hour batteries, ¾ of imports were completed; with 4-hour batteries, only around half of imports were completed. At times of network constraint, batteries must trade at lower power, and so require more timesteps to complete the action. The pattern of wholesale pricing usually allowed a 2-hour battery the additional time to complete its trades, however the additional time required by a 4-hour battery was often too long for the price to remain favourable for the duration of the trade, and battery activity was reduced. It is thus not surprising that the curtailment costs at all locations were higher for the 4-hour than the 2-hour batteries.

7.5.5. Effect of location characteristics

While there are similarities in patterns of curtailment cost across all locations, there are differences between locations.

Curtailment costs are generally higher at the most strongly generation-dominated locations (Fairlie, and in summer, Lochan Moor), and also at demand-only Stevenson, compared to Largs and Armadale, where there is sizeable town demand as well as a significant wind generation.

Part of the reason for this is the “headroom limit” approach used. “Worst case” conditions for highest network flows at Largs and Armadale only happen when both high generation and low demand to occur at the same time. At Largs and Armadale, such conditions occur less often than at Stevenston, where demand peaks occur every day with no generation to reduce imports, or at Fairlie, where there is very little demand to reduce circuit flows from the windfarm outputs. This shows, slightly surprisingly, that the best locations to site a battery, if considering network constraints, would be those where a mixture of both demand and generation flows often allow greater available network capacity than at a demand-only or generation-only site.

Stranraer

Stranraer is something of an outlier in this analysis, having similar magnitudes of maximum demand and generation flows, yet relatively high curtailment costs, similar to demand-only Stevenston. Two factors are suggested by way of explanation.

First, during windy autumn season, the network topology is a factor. The battery, located at the same bus as the windfarm, has exports via the 11kV bus and OHL 2 limited by the capacity of transformer T1, at times of battery export coinciding with significant wind output. This contrasts with Armadale, where demand and generation, both connected to the 11kV bus, can allow battery exports up to any spare capacity of both OHLs, with transformer T1 only limiting exports for very large battery sizes. This suggests, again surprisingly, that from a battery point of view, connection at the same bus as a windfarm may limit the battery's opportunity to export at times of favourable price but high wind output.

A further contributory factor for surprisingly high curtailment costs at Stranraer is the high number of curtailed imports, especially during the summer season. The windfarm at Stranraer had particularly low output during the summer, and network flows were more often demand-dominated than export-dominated. Furthermore, the pattern of demand flows aligned poorly with price data, in a similar manner to that described above for Stevenston.

Overall

The above work suggests that network locations with a mix of generation and demand would generally allow greater capacity for battery activity than those which are very strongly demand- or generation-dominated. However, one exception has been found, which shows that site specific characteristics, including network topology and individual demand and generation flow patterns, are also significant, and may have substantial impacts on overall curtailment costs.

7.5.6. For "2-feeder" locations, costs under "N-1" conditions are significant at some battery sizes, and should be considered.

This analysis found that curtailment costs resulting from the occurrence of 'N-1' conditions were generally low, but could amount to up to 3% and 5% of unrestricted battery overall net revenues, for medium and high failure rates respectively, on network with long feeders, for the largest batteries modelled. These calculations also assumed that the battery operator can amend its schedule with some foresight of network constraints; without any such foresight, constraint costs would be higher.

The costs were based on long-term average failure rates and daily costs of curtailment averaged over the whole year. Clearly the duration of outages will vary from year to year, and the cost of curtailment during such outages will be sensitive to prevailing conditions of wholesale price, renewables outputs and demand patterns. Further work of probabilistic modelling of costs of curtailment during the various "N-1" events considered, and potentially also "N-2" events, is recommended.

Consideration of “N-1” conditions is especially pertinent in the light of recent guidance [102], as described in Section 7.2.3, which would have batteries, even connected with firm connections, subject to curtailment during network outage events.

7.6. Conclusions

This chapter addresses the research question:

“If there are any negative consequences of battery deployment, what mitigation measures might be appropriate?”

Here, the mitigation measure under consideration is a flexible (i.e. non-firm) connection, in which the battery owner would bear the cost of curtailment.

This work has found that batteries can indeed be significantly oversized, compared to the available network capacity after “worst case” activity from other network users, termed “network headroom”.

- Oversizing by up to 10 – 20 MW, compared to the available network “headroom”, results in curtailment costs for the battery, but such costs are relatively modest, in many cases up to around 5% of the overall net revenue a battery would accrue if connected to a network with ample spare capacity.
- Costs of curtailment rise more rapidly with further oversizing of the battery. Average curtailment costs were estimated at between 10% and 35% of overall net revenue on an unconstrained network for the largest batteries investigated – oversized, compared to available network headroom, by 20 MW for the single-feeder locations, and up to 40 MW for two-feeder locations.
- Curtailment costs vary significantly between seasons
- Curtailment costs vary significantly with battery duration, with longer duration (4 hour batteries) having roughly double the curtailment costs of shorter duration (2 hour) batteries. This cost difference is higher than might be expected, given that 4-hour batteries would accrue approximately 1.5 times the revenue of a 2 hour battery, as shown in Chapter 6.
- The nature of network flows. Batteries connected to networks which are either very strongly generation dominated, or demand-only, in most cases had higher curtailment costs than batteries connected to networks which were more moderately generation-

dominated. However, one location, Stranraer, was an exception to this pattern, having similar maximum generation and maximum import flows, but also relatively high battery curtailment costs.

- For networks with two feeders connecting the key demands and generators, curtailment costs under “N-1” conditions are significant, compared to those under normal operating conditions, for batteries sized up to around 20 MW in excess of network headroom, though even at this size, curtailment costs were only up to between around 1% and 4% of unconstrained net revenues at medium and high failure rate scenarios. At larger battery sizes, the “N” costs dominate.
    - “N-1” costs are most significant for
        - “medium” and “high” failure rate scenarios, (compared to the “low” failure rate scenario)
        - for a location with long feeders,
        - for outages occurring during periods of
            - high network flows, whether demand or generation-dominated;
            - high potential battery revenues.
            - Mismatch between timeseries patterns of local network flows and electricity wholesale pricing

Regarding methodology, the use of a “network headroom” concept allows direct comparison of different locations, with different quantities of unused network capacity.

In general, this chapter has found that could indeed be merit in connecting batteries with non-firm connections. This finding concurs with the generic recommendations of ENA’s Tactical Guidance [102] previously raised in Chapter 3, which recommends that DNOs connect batteries with “less firmness of connection” than other network users, under conditions of network faults. The work of this thesis chapter goes further than the ENA’s guidance, in that it suggests it could be advantageous to connect batteries with non-firm connections under both normal and abnormal network conditions.

This chapter lays the ground for comparison of costs of curtailment with the costs of network reinforcement, which is considered in the following chapter.

8. Chapter 8 Comparison of battery curtailment with network reinforcement

Chapter summary

A classic approach to *transmission* network planning is that the "optimum" amount of network for society is the one at which the total costs – arising from both the infrastructure itself, and of the costs of network constraints - are at a minimum. This chapter applies this approach to the distribution network case studies investigated in the preceding two chapters. The scenario of a battery connected with a non-firm connection and subject to curtailment, whose costs are enumerated in the preceding chapter, is compared with an alternative scenario in which the network in reinforced by a single line, of capacity ~ 20 MVA in each case. The "no reinforcement" scenario was found to have the lowest overall cost, compared to "reinforcement" option, for batteries oversized compared with available network capacity, by between 2.5 MW and 42 MW, depending on location, battery duration, and whether or not the battery project was assumed to be repowered at the end of the battery's expected life. Taking a "seek the lowest overall cost" approach, the "reinforce" option is relatively better where reinforcement costs are low, battery duration (and hence curtailment costs) are greater, and where the battery project is expected to continue beyond the expected ten years lifetime of a battery itself.

There are other approaches to considering the question of whether or not to reinforce the network. If the reinforcement is considered to be necessary in the future under any circumstances, then the cost of the battery-triggered reinforcement could be considered to be the time value of moving the reinforcement earlier: such a view would normally be lower cost than considering the cost of the reinforcement outright, and is likely to make "reinforce network" appear more attractive over a wider range of battery sizes.

The apportionment of reinforcement costs between a battery and developer is discussed, specifically the extent to which it encourages a lowest cost solution. The question of whether, indeed, "seeking the lowest overall cost solution" is the most appropriate one, and whether reinforcement costs are *fairly* apportioned, are complex. Answering these requires consideration of wider questions, including: "*does reinforcing the network bring wider value to* *other customers who might use additional capacity?"* and *"what value does the presence of batteries bring to networks?"* recognising that batteries are able to provide flexibility services, if suitably incentivised. There is no single answer to these questions, and discussion of these matters continues in the Conclusions chapter.

8.1. Introduction and aim

This chapter applies a concept traditionally used in transmission network planning to the distribution network case studies described in the preceding two chapters. The "optimum" amount of network is defined as that with lowest overall costs, considering costs arising from both reinforcement and lack of reinforcement [249], as shown schematically in Figure 116. (It is noted that several of the prior works reviewed in Chapter 2 aimed to use storage deployment to minimise overall distribution network costs, considering the costs of both reinforcement, and of capacity constraints, including costs of renewable energy curtailment and energy not served in constraint costs [67], [78].)

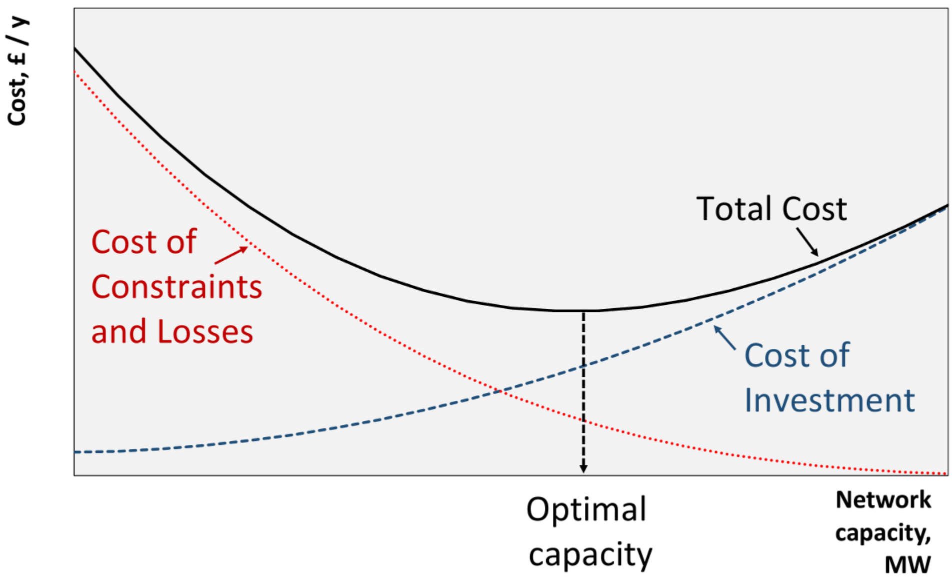


Figure 116 Schematic diagram of cost-benefit approach to transmission planning, concept shown in [249]

This work builds on that of the previous chapter, taking costs of curtailment of the batteries at the aforementioned case study locations. This chapter aims to compare the costs of curtailment these curtailment costs, for different battery sizes, with those of network reinforcement. This work thus seeks to find battery sizes, at all the locations, at which the curtailment costs and reinforcement costs are equivalent. These findings can inform decisions about where and when network reinforcement may be a lowest total cost approach, and where choosing to reinforce, or not to reinforce, may be lower in overall cost.

The chapter explores broader considerations about the "lowest overall cost" approaches, whether current charging arrangements do or even should encourage a "lowest overall costs" approach.

8.2. Methodology overview

8.2.1. High level comparison: to reinforce or to not reinforce?

Using the case study locations of the previous two chapters, this work seeks to find a financial comparison between two alternative options:

- **Option A: Reinforce network**: construct one single additional 33kV OHL from battery bus to GSP.
- **Option B: Do not reinforce network**.

All costs are calculated, as Net Present Values (NPVs), over projected lifetime of a reinforced network asset, taken to be 40 years.

The main features of both options, and selected metrics for comparison, are shown in Table 57.

Table 57 Comparison of "Reinforce network" and "Do not reinforce network" options

	Option A	**Option B**
	Reinforce network	**Do not reinforce network**
Reinforcement envisaged	1 * 33kV OHL from battery bus to GSP	None
Reinforcement capacity	Identical to that of existing OHL (single OHL case study locations) / OHL 1 (2-feeder case study locations)	N/a
Metrics selected for comparison	CAPEX cost of reinforcement (2022 value) + NPV (2022) of all future residual (reduced) battery curtailment costs, on the reinforced network, over chosen scenario of project lifetime	NPV (2022) of all future battery curtailment costs, over chosen scenario of project lifetime

Key variables

There are three main parts to these cost comparisons:

- **Cost 1**: The capital cost of network reinforcement – part of Option A ("reinforce")
- **Cost 2**: The cost of ongoing battery curtailments – with no reinforcement - Option B ("Do not reinforce")
- **Cost 3**: The cost of residual ongoing battery curtailments on the network (if any), even after the reinforcement work – part of Option A ("Reinforce")

8.2.2. Modelling approach

Option A: "Reinforce network"

As stated above, the cost of a scenario in which the network is reinforced has two cost components: the reinforcement works, and also any remaining (reduced) battery curtailment costs.

$$cost_{reinforce\_network\_option} = cost_{networkreinforcement} + cost_{residualbatterycurtailment} \quad (8.1)$$

Or, referring to "Cost 1", "Cost 2" and "Cost 3" above,

$$Cost_{OptionA} = Cost1 + Cost3 \quad (8.2)$$

The *network reinforcement cost* part of the overall "reinforce network" option uses generic network costings data, in £/km OHL, adjusted for 2022 costings, as outlined later in section 8.3.1. Location-specific costs are obtained for each case study location based on its feeder length.

The *residual battery curtailment cost* part of the "reinforce network" option is calculated in a similar manner to battery curtailment cost calculation for the "do not reinforce" option, as described below for Option B. The additional network capacity available in this scenario significantly reduces the frequency and severity of battery curtailment events, compared to the "no reinforcement" case.

Option B: "Do not reinforce"

The costs of the "do not reinforce" options are entirely costs of battery curtailment:

$$Cost_{do\_not\_reinforce\_option} = cost_{batterycurtailment} \tag{8.3}$$

Or,

$$Cost_{OptionB} = Cost2 \tag{8.4}$$

These battery curtailment costs are calculated as follows

- Cost of curtailment at each location, as described in the previous chapter, for
    - a range of battery sizes (MW) in excess of network headroom,
    - batteries able to operate for 2 hour and 4 hour durations
    - annual curtailment cost estimates, based on costs for each case study season,
    - normal "N" circuit conditions
- For the three "2-feeder" locations, cost of curtailment was amended to take into account "N-1" conditions, using a medium failure rate scenario (only), as described in the previous chapter
- Future battery curtailment costs are reduced, to take into account expected battery lifetime and degradation, and all future costs are discounted, in:
    - a base case *"1 lifetime"* scenario (taken to be 10 years), after which battery operations cease
    - an additional scenario which assumes the battery project is *repowered* with a new like-for-like battery every ten years. Thus the battery project operates for 40 years. This scenario is called *"4 lifetimes"*

Overall, the approach used for comparison of the "reinforce" vs "do not reinforce" options is summarised in Figure 117.

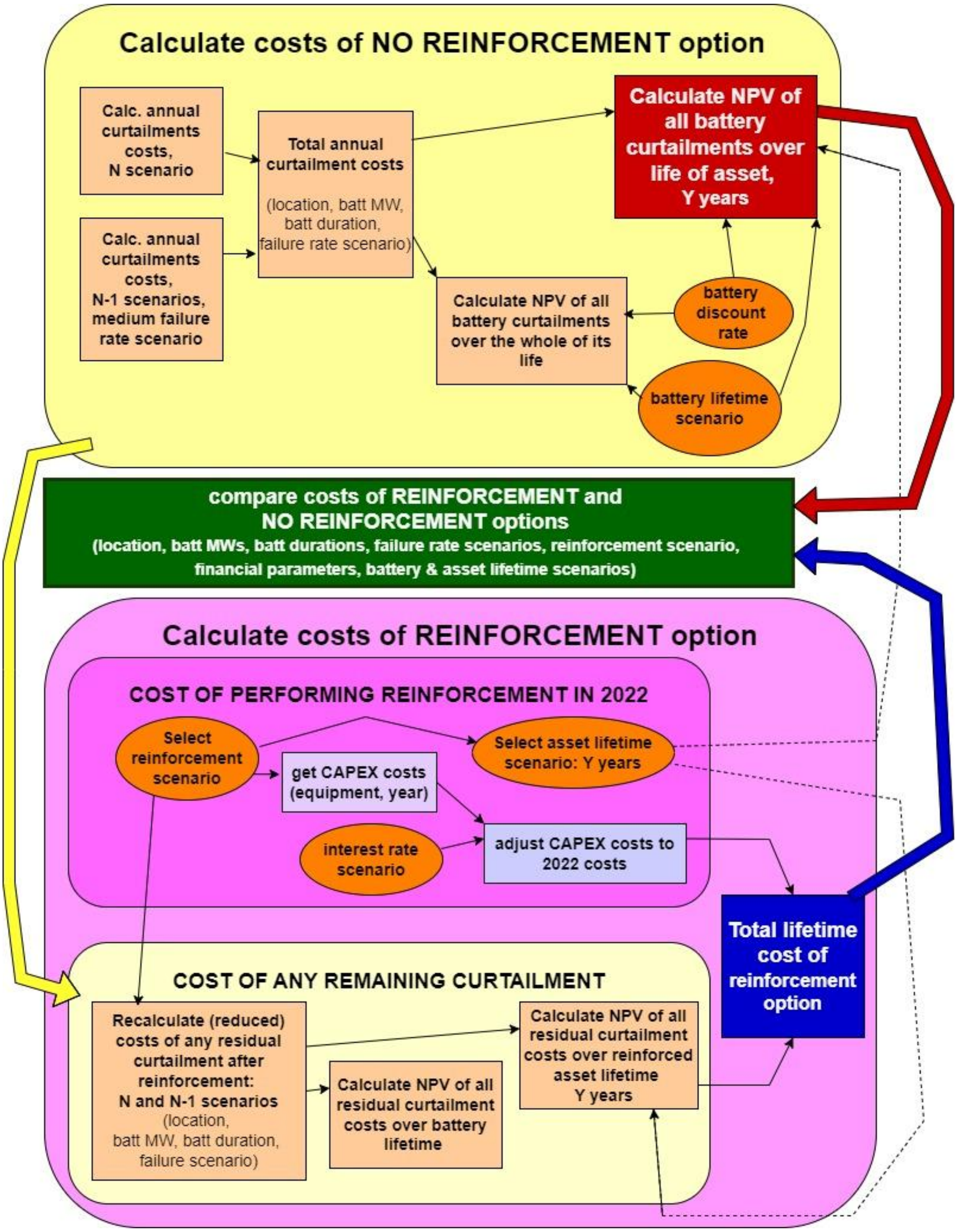


Figure 117 Flowchart summarising approach to comparison of "Reinforce network" vs "Do not reinforce" options [79]

[79] KEY: Orange ellipses - scenarios; pale blue / violet boxes – finding CAPEX costs; brown boxes – intermediate cost calculations; deep red / blue / green box – final calculations.

8.3. Detailed methodology: comparison of costs of network options considered

This section describes the calculations of all costs for both options considered, namely:

- "reinforce network" and
- "do not reinforce network"

Subsection 8.3.1 describes the approach used to enumerate *network reinforcement costs* (termed "***cost 1***" in Section 8.2, part of overall costs of ***Option A, reinforce network***). This section states the costing source data used, method of adjusting these (old) costs to 2022 costs, and details of envisaged reinforcements. This section ends with tabulated projected reinforcement costs at all case study locations.

Subsection 8.3.2 describes the calculation of NPV of battery curtailment costs, over the whole of the battery lifetime, in a scenario with *no network reinforcement* (termed "***cost 2***" in Section 8.2, the costs of ***Option B, do not reinforce network***). This section lists key financial metrics used, and assumptions regarding battery degradation and battery lifetime, and their effects on future curtailment costs. This section also considers an additional battery scenario, in which the battery is repowered.

Subsection 8.3.3 describes the method used to calculate the *reduced* NPV of battery curtailment costs, *after* the proposed reinforcement, for each location.

Subsection 8.3.4 describes how the above costs are combined, to yield projected costs for the "reinforce" and "do not reinforce" options, for each case study location.

8.3.1. Costs of traditional reinforcement of network (part of the costs of "Reinforce network" option)

The default approach to a developer's connection request, which may at times exceed network capacity, would be to perform traditional reinforcement, covering the overhead line (OHL), substation, or any other relevant equipment. Such works would normally increase network capacity by an amount sufficient to allow a the developer to connect with a firm connection. The section below discusses likely costs of reinforcement work in the above case studies, in order to compare the costs of this approach with those of battery curtailment.

The capital costs of network reinforcement, £/ km OHL, and £/ transformer, were estimated, using Table 14.2, Appendix B, Review of Distribution Network Security Standards, Extended Report, to the ENA, March 2015, by Imperial College London [248], [250]. In all cases "EHV pole OHL" costings were used.

The costs – presumed to be 2014 costs - were increased by a rate of 3% pa, compounded annually, over the intervening 8 years, to estimate equivalent 2022 costs.

$$CAPEX\ cost_{2022} = CAPEX\ cost_{2014} * (1 + r)^n \tag{8.5}$$

Where

r = rate of interest, taken as 3% p.a.

n = number of additions of interest, taken as 8

The report states that the costs all had a large error margin (+ / - 20%); uncertainties in applicable interest rate during the intervening 8 years add to the potential error, so all costs are approximate.

Table 58 "Average asset replacement cost", based on [248], [250]

Voltage level	Asset name	Cost, £k/ km, as reported (in 2015)	Estimated costs, £k / km, in 2022, based on 3% interest p.a.
EHV	OHL pole	39	49.40

For each case study location, the distance in km of potential reinforcement was listed in SPEN LTDS documents, as listed in Table 32, in Chapter 6.

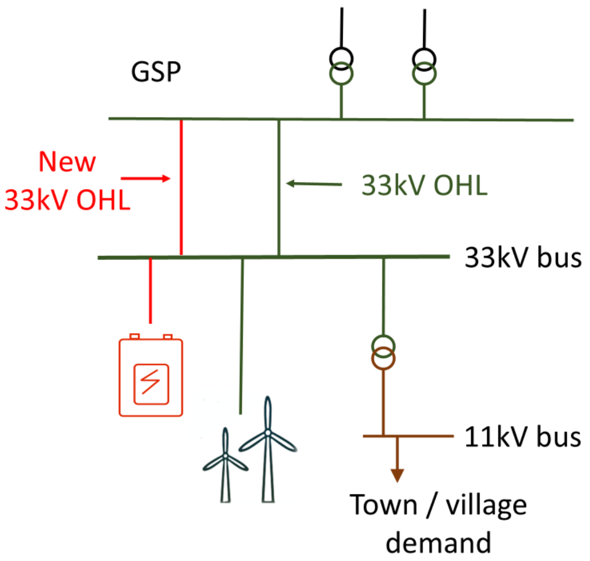
The reinforcement scenario selected is the lowest-cost reinforcement that would add significant additional network capacity. It assumes that no additional substation capacity would be needed at GSP. Costs of additional switchgear and other equipment were neglected.

Reinforcement details

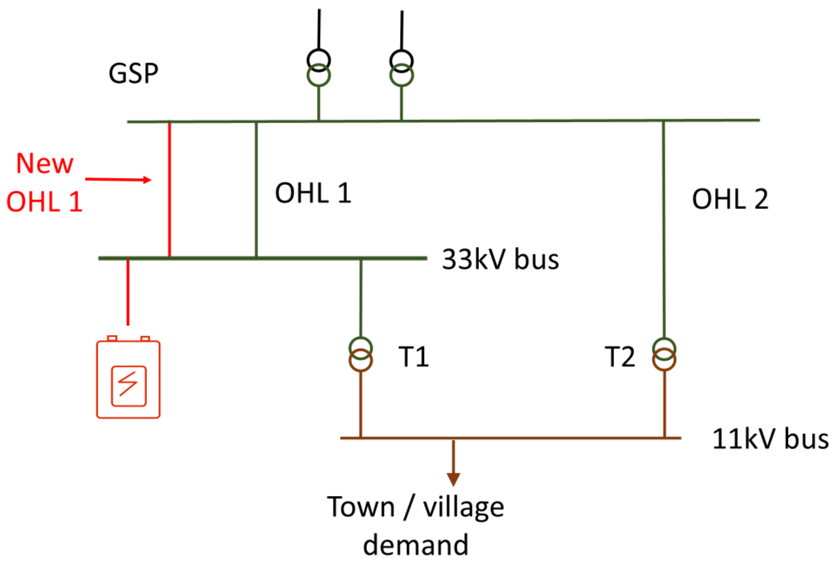
For all locations, the envisaged reinforcement would consist of an additional pole OHL, from the 33kV bus to which the battery connects, to the GSP, as shown on Figure 118.

The additional capacity is assumed to be the same as that of the existing OHL / OHL 1, around 20 MVA in every case.

The lifetime of the reinforcement is taken to be 40 years.



(a)



(b)

Figure 118 Reinforcement scenario considered for (a) the single-OHL case study locations; (b) the 2-OHL case study locations

The calculated cost of reinforcement for each case study, using the £49.40 k per km value shown above, is tabulated below in Table 59.

Table 59 Parameters and reinforcement cost of 33kV OHL at the case study locations

Location	33kV OHL	Other 33kV connection	Branch thermal limit, MVA			Branch length, km	Reinforcement cost, £ k (2022)
			Summer	Autumn	Winter		
Lochan Moor		North Rhinns windfarm	21.6	21.6	22.4	14.52	**717**
Largs		Kelburn B windfarm	20.9	20.9	21.74	16.463	**813**
Fairlie		Kelburn A Windfarm	20.86	20.86	20.86	15.131	**748**
Armadale	OHL 1		19.71	19.71	20.86	1.84	**91**
	OHL 2		19.71	19.71	20.86	1.85	n/a
Stranraer	OHL 2		19.71	19.71	24.63	13.6	n/a
	OHL 1	Glenchamber windfarm	19.71	19.71	24.63	15.1	**746**
Stevenston	OHL 2		16.29	16.29	16.29	3.74	n/a
	OHL 1		19.71	19.71	20.86	3.66	**181**

8.3.2. Cost of ongoing battery curtailments (“no network reinforcement” scenario)

Average cost of curtailment, over the year of 2022

Whole-year curtailment costs are calculated for all locations, battery sizes (MW) for 2 and 4-hour duration batteries, as described in Chapter 7.

For the three “2-OHL” locations, curtailment costs under abnormal ‘N-1’ network conditions, as well as under normal “N” conditions are considered. N-1 curtailment costs are considered for the medium failure rate scenario only, as described in the previous chapter.

These curtailment costs are tabulated in Chapter 8 Annex 1.

Conversion of annual curtailment costs to “Whole lifetime” costs

First, it is assumed that all future years will have wholesale price and network flows patterns as in 2022, i.e. that curtailment costs a new battery would experience would be the same every year. This is a strong assumption. Ideally, projection of future “battery lifetime” curtailment costs would be based on a study over a much longer duration, perhaps several years.

However, there is inevitable uncertainty with any projections of future costs, and historical data may not be good predictors of the future. For example, wholesale electricity price data during 2015-2021 would not have predicted the prolonged rise and volatility in prices seen during periods of 2022. Looking ahead, the UK Government's "Clean Power 2030" and "Net Zero" targets [6], [21], [22] require a transformation of GB's electricity and wider energy systems. Attainment of these targets is likely to involve greater penetrations of weather-dependent renewables, generation which it is envisaged will displace gas as the price-setter for much of the time, and may result in more frequent occurrences of near-zero wholesale prices. However, electrification of heat and transport demands currently met by fuels is predicted to lead to higher peak demands [251], demand peaks which are sometimes accompanied by high prices[80]. Furthermore, "low carbon despatchable" electricity generation, such as gas power plants with carbon capture and storage fitted, or fuelled by a "green gas"[81] [252], deployment expected beyond 2030 [227], [251], is likely to be higher cost than current unabated gas generation, and may magnify wholesale gas price variations. Altogether, the levels of volatility in electricity prices seen in 2022 (volatility which drives incomes for battery engaged in arbitrage, and the costs of any curtailment) may indeed represent that in a future "clean power" system. Therefore, the use of case study data is considered justified, as a first approximation, though these results should be viewed with an understanding of the limitations of the data on which they are based.

The annual curtailment costs of the batteries, and the CAPEX of envisaged network reinforcement, cannot be *directly* compared, because they occur over different timescales. Furthermore, battery projects and network assets have different lifetimes and different financial discount rates are expected.

The chosen metric for curtailments, suitable for comparison with reinforcement CAPEX costs, is the Net Present Value of all future battery curtailment costs, occurring over the lifetime of the network asset.

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[80] Such as system several stress events in Nov and Dec 2022. In the Annexes to Chapter 5, Annex 6.8, scatterplots of wholesale electricity price vs transmission system demand for the case study periods in 2022, showing occasional exceptionally high prices during the winter case study period, at on some occasions of high system demand.

[81] "Green gas" could include biomethane, or hydrogen made from reformation of natural (fossil gas) or another fossil fuel, accompanied by carbon capture and storage, or hydrogen made from electrolysis of water

Three different factors are taken into account when estimating total lifetime curtailment costs:

- The effect of battery degradation on future curtailment costs
- The effect of financial discounting on future curtailment costs
- Whether or not the battery project is re-powered at the end of its lifetime

Battery degradation

A ten year service life of the battery is assumed, during which degradation of battery is assumed to occur. Battery degradation is likely to reduce battery duration and / or capacity, and potentially increase round-trip losses, all of which would reduce the overall amount of curtailment the battery would endure. The following scenario is selected:

$$curtailment\ costs(batt\ degradation)_{10years} = curtailmentcosts_{new} * 50\% \quad (8.6)$$

Assuming linear reduction of curtailment costs with time, curtailment costs after 'y' years is as shown in Eqn. 8.7 below:

$$curtailment\ costs(batt\ degradation)_{y} = curtailment\ costs_{y=0} * (1 - 0.05 * y) \quad (8.7)$$

Financial discounting

The effect of financial discounting on future curtailment costs at year y is shown on the equation below.

$$NPV\ of\ curtailment\ \ cost(discounted)_{y} = curtailment\ cost_{y=0} * (1 + r)^{y} \quad (8.8)$$

Where: r = discount rate, taken as 8% p.a., added annually

Battery lifetime and repowering

Two scenarios are investigated.

One battery lifetime scenario

The "One lifetime" scenario assumes at the end of the battery's ten year lifetime, the project ends.

Thus, combining the above two equations:

$$NPV\ of\ whole\ lifetime\ curt.costs_{1battlifetime}$$
$$= curt.costs_{2022} * \sum_{y=0}^{y=9}(1-0.05*y).(1+r)^{y} \tag{8.9}$$

A spreadsheet listing the projected curtailment of every year is appended in Chapter 8 Annex 2, Table 133. The result of the above calculation is :

$$NPV\ of\ whole\ lifetime\ curt.costs_{1battlifetime} = curt.costs_{2022} *\ 5.884 \tag{8.10}$$

Four battery lifetimes scenario

An additional scenario regarding battery project lifetime is introduced here.

The "Four battery lifetimes" scenario assumes that the battery project is repowered at the end of the battery's ten year life, each ten years, up to thirty years. Thus battery curtailment costs continue for forty years are as shown in Eqn. 8.11:

A spreadsheet listing the projected curtailment cost of every year is appended in Chapter 8 Annex 2, Table 134.

$$NPV\ of\ whole\ lifetime\ curt.costs_{4battlifetimes}$$
$$= curt.costs_{2022} * \left[\sum_{y=0}^{y=9} (1-(0.05*y)).(1+r)^y + \sum_{y=10}^{y=19} \left(1-\left(0.05*(y-10)\right)\right).(1+r)^y + \sum_{y=20}^{y=29} (1-0.05*(y-20)).(1+r)^y + \sum_{y=30}^{y=39} \left(1-\left(0.05*(y-30)\right)\right).(1+r)^y \right] \quad (8.11)$$

The result of the above calculation is :

$$NPV\ of\ whole\ lifetime\ curt.costs_{4battlifetime} = curt.costs_{2022} * \ 10.386 \quad (8.12)$$

Key parameters for both “1 lifetime” and “4 lifetimes” scenarios are show in Table 60.

Table 60 Key parameters used in calculating whole life battery curtailment costs

Battery lifetime scenario	**“1 lifetime”**	**“4 lifetimes”**
Battery lifetime	10 years	10 years
Curtailment costs at end of battery lifetime	50% of initial	50 % of initial
Financial discount rate	8% p.a., added annually	8% p.a., added annually
Battery repowering scenario	No repowering. Battery project operates for one single battery lifetime	Repowering occurs. Battery is replaced every ten years for thirty years.
Battery project lifetime	10 years	40 years
NPV lifetime costs multiplier[82]	5.884	10.386

NPVs of annual and projected whole project lifetime curtailment costs are shown in Chapter 8 Annex 3.

[82] to be multiplied with annual curtailment costs to obtain NPV of projected whole battery project life costs

These “NPV lifetime costs multipliers”, used together with location-specific curtailment costs for battery across the range of sizes, are key to estimating what would be the overall cost of the “do not reinforce” option.

Put simply, a low NPV cost multiplier is a statement that *lifetime* curtailment costs of the battery are little different from those over a single year, i.e. relatively modest, a finding which favours “do not reinforce” as being the lower cost option, for a wide range of battery sizes and / or location-specific reinforcement costs. Conversely, a high NPV lifetime cost multiplier here is a statement that battery curtailment costs over its lifetime are significant, a finding that would favour “reinforce network” as being the lower cost option, over a wider range of battery sizes and site-specific costs.

8.3.3. Costs of residual (reduced) battery curtailment, after proposed network reinforcement[83]

The proposed network reinforcement would reduce but not eliminate all further battery curtailment for the larger battery sizes modelled. These costs need to be included in estimates of overall costs of “reinforce network” option. Costs of residual battery curtailment are enumerated as follows.

8.3.3.1. Fairlie, Largs and Lochan Moor: N conditions

The proposed network reinforcement would add just over 20 MVA of additional network capacity. As battery sizes of up to 20 MW in excess of network headroom were modelled at these locations, an additional 20 MW of capacity would eliminate further curtailment at these battery sizes. Residual curtailment costs are therefore zero.

8.3.3.2. Fairlie, Largs and Lochan Moor: abnormal (“N-1”) conditions

It is assumed that the proposed reinforcement would be an additional OHL which would operate in addition to the existing OHL. It is also assumed that either line could fail independently of the other, i.e. unlike in the base case scenario, there is now redundancy in the network, and a failure in either the original or the new OHL would allow continuity of supply to the town / villages which connect downstream. However, such a failure would reduce capacity available to the battery, as previously discussed, and so such abnormal network conditions should be considered.

[83] Residual costs of battery curtailment is an additional cost component in the “reinforce network” scenario

$$network\ capacity_{afterreinforcement}\ (N) = network\ capacity_{beforereinforcement} * 2 \quad (8.13)$$

$$network\ capacity_{afterreinforcement}\ (N-1) = network\ capacity_{afterreinforcement}(N) * \frac{1}{2} \quad (8.14)$$

$$network\ capacity_{afterreinforcement}\ (N-1) = network\ capacity_{before\ reinforcement}(N) \quad (8.15)$$

Thus, considering the cost of reinforcement,

$$cost\ of\ curt'_{afterreinforcement}(N-1)PERDAY$$
$$= cost\ of\ curt'_{beforereinforcement}(N)PERDAY \quad (8.16)$$

$$cost\ of\ curt'_{afterrinforcement}(N-1)\ PER\ YEAR$$
$$= cost\ of\ curt'_{beforereinforcement}(N)PER\ DAY * \frac{\frac{no.of days}{yr}(N-1)conditions}{365.25} \quad (8.17)$$

The number of days per year of expected N-1 conditions is calculated as in the previous chapter, using a Medium failure rate scenario for OHLs of 8.5% failure rate per km year. Again, it is assumed that failures do not occur coincidentally. Failure rates are calculated as previously described in Chapter 7.

$$no\frac{days}{yr}(N-1)conditions$$
$$= failure\ rate(perkm.yr) * branch\ length(km) * MTTR(days) \quad (7.34)$$

After reinforcement, it is assumed there are now *two* branches, so Eqn. (7.34) is adapted:

$$no\frac{days}{yr}(N-1)conditions$$
$$= failure\ rate(perkm.yr) * single\ branch\ length(km)$$
$$* 2\ (branches) * MTTR(days) \quad (8.18)$$

The number of days per year of expected (N-1) conditions are tabulated in Table 139 in Chapter 8 Annex 4. The projected residual annual curtailment costs, after reinforcement, and their respective projected whole lifetime Net Present Values, are tabulated in Table 140, Table 141 and Table 142 in the same annex.

8.3.3.3. Armadale, Stranraer and Stevenston, 'N' conditions

At these locations, batteries up to 40 MW in excess of network headroom are modelled, and so even with ~ 20 MW reinforcement, some curtailment will continue to occur for larger batteries.

The costs of residual curtailment were worked out by running further battery simulations, using the same method as described in Chapter 7, but with the network capacity adjusted to have extra OHL capacity, of the same capacity, at every season, of OHL 1.

8.3.3.4. Armadale, Stranraer and Stevenston, 'N-1' conditions

The residual curtailment costs were calculated in a similar manner to the method in Chapter 7.

For the abnormal network conditions: OHL2 or T2 unavailable, and T1 unavailable, battery simulations were re-run, with additional network capacity, as described in the previous paragraph. The number of days/ year of their occurrence is as for the these 'N—1' conditions on the unreinforced network, as described in Chapter 7.

For abnormal condition in which either the original OHL 1, or the new OHL 1 is unavailable, these network conditions are identical to that of the original network, before reinforcement under 'N' conditions. The number of days / year these conditions occur in each case is the number of days/ year of "OHL 1 inoperable", as described in Chapter 7.

8.3.3.5. Armadale, Stranraer and Stevenston, overall residual curtailment costs

As in Chapter 7, the curtailment costs of 'N' conditions are adjusted to take account of 'N' conditions not occurring every day, i.e. not on days of 'N-1' conditions.

Overall curtailment costs are the sums of the adjusted curtailment costs under 'N', and of the costs of curtailment of all 'N-1' scenarios, as shown below. The "N curtailment costs" and "N-1 curtailment costs for each "N-1" scenario are all projected annual curtailment costs, £/year, in a scenario in which those conditions occurred every day of the year.

$$Overall\ residual\ curtailment\ \ costs$$
$$= residual\ N\ curt\ costs * \left(1 - \left(\frac{\sum days\ per\ year_{all\,(N-1)conditions}}{365.25}\right)\right)$$
$$+ \sum\nolimits_{all(N-1)scenarios} \left[residualcurt\ costs_{(N-1)scenario} \cdot \frac{days\ per\ year(N-1)conditions_{(N-1)scenario}}{365.25}\right] \tag{8.19}$$

Projected overall annual residual curtailment costs are then used to estimate the NPVs of whole lifetime residual curtailment costs, under “1 battery lifetime” and “4 battery lifetime” scenarios. These results are presented in Section 8.4. All values are tabulated in Table 143, Table 144 and Table 145 in Chapter 8 Annex 4.

8.3.4. Total projected costs of “Reinforcement Option” vs “No reinforcement option”

For each case study location and battery size (MW capacity, duration), the projected cost of the reinforcement option is the sum of the CAPEX reinforcement cost, plus the applicable projected NPV whole battery project lifetime curtailment residual curtailment cost, after reinforcement, as described in the Section 8.3.3.

$$Total\ cost: reinforcement\ option$$
$$= CAPEX\ reinforcement_{2022,location}$$
$$+ NPV\ whole\ lifetime\ residual\ curtailment\ cost_{location,battMW,battdur'n,battlifetimescenario} \tag{8.20}$$

Where CAPEX costs are enumerated previously in Section 8.3.1, and residual curtailment costs in Section 8.3.3.

Total “Reinforcement option” costs are tabulated in Chapter 8 Annex 5.

The costs of the “Do not reinforce” option are as previously described in Section 8.3.2., and tabulated in Chapter 8 Annex 3.

8.4. Results: Comparison of costs of “Reinforce network” with “Do not reinforce network” options

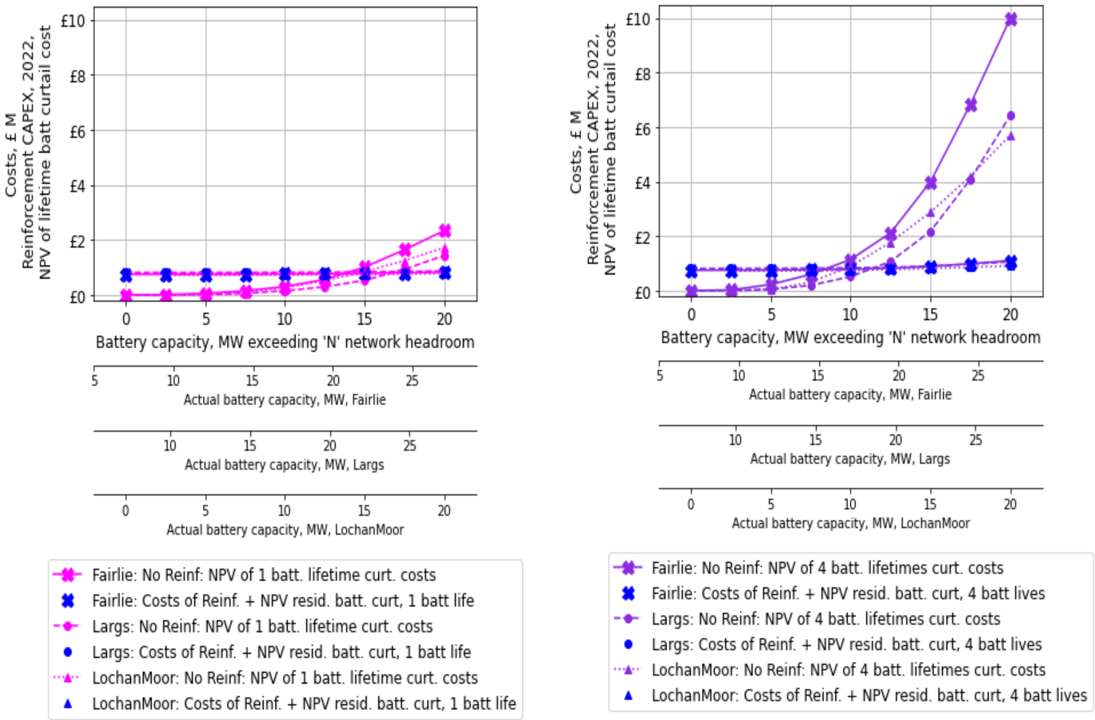
This section shows how the costs of the “no reinforcement” option, i.e. battery curtailment, compare with costs of the “reinforcement” option, calculated as described in the previous section, for the different sites and across different battery sizes.

8.4.1. Full range of battery sizes and costs

Figure 119 below shows one example from the results set: for Fairlie, Largs and Lochan Moor.

First, the blue symbols form a near-horizontal line, depicting the cost of the “reinforce” option. The three locations have similar lengths of branches to be reinforced, so the reinforcement costs are similar. Furthermore, at this size of battery, the costs of residual curtailment after reinforcement are small, compared to the cost of the OHL itself, so this former component is barely evident at this scale.

As in the previous chapter, the “battery size (MW) *in excess of network headroom*” approach is used, which seeks to “normalise” battery sizes across locations against the network capacity that would be available to a battery, taking into account network thermal limits, and “worst case” use by other connected users. “Battery size in excess of headroom”, is used for the x-axes of the charts below; the sizes of actual batteries are shown below as secondary x-axes.



(a) 2hr batteries, 1 lifetime scenario (b) 4hr batteries, 4 lifetimes scenario

Figure 119 Costs of “reinforce” and “do not reinforce” options., Fairlie, Largs and Lochan Moor. (a) 2-hour batteries, “1 battery lifetime scenario. (b)) 4-hour batteries, “4 battery lifetimes” scenario

The pink and purple curves show the full curtailment costs in the “do not reinforce” scenario: the pink curve in graph (a) for the “1 battery lifetime” scenario, and the purple curve in graph (b) for the “four lifetimes” scenario, respectively. Both show a broadly similar trend: starting at zero for the smallest batteries, and rising with increasing battery size to significantly surpass the costs of the “reinforce” option at the larger battery sizes.

Graph (b) has much higher costs of the “do not reinforce” option than graph (a), by a factor of approximately 4, because of the combined effects of longer battery duration and the different “battery lifetime” scenario. As described in the previous chapter, 4 hour batteries have roughly double the curtailment costs of those of 2 hour batteries of the same capacity, for much of the battery size range. As described in Section 8.3.2, the “four lifetimes” scenario, with battery repowering every ten years, has almost double the projected lifetime curtailment costs of the “one lifetime” scenario. The full set of graphs (2hr and 4hr, for both 1 and 4 lifetimes scenarios) are appended in Chapter 8 Annex 6.

Figure 120 shows an example of a corresponding curve for Armadale, Stranraer and Stevenston.

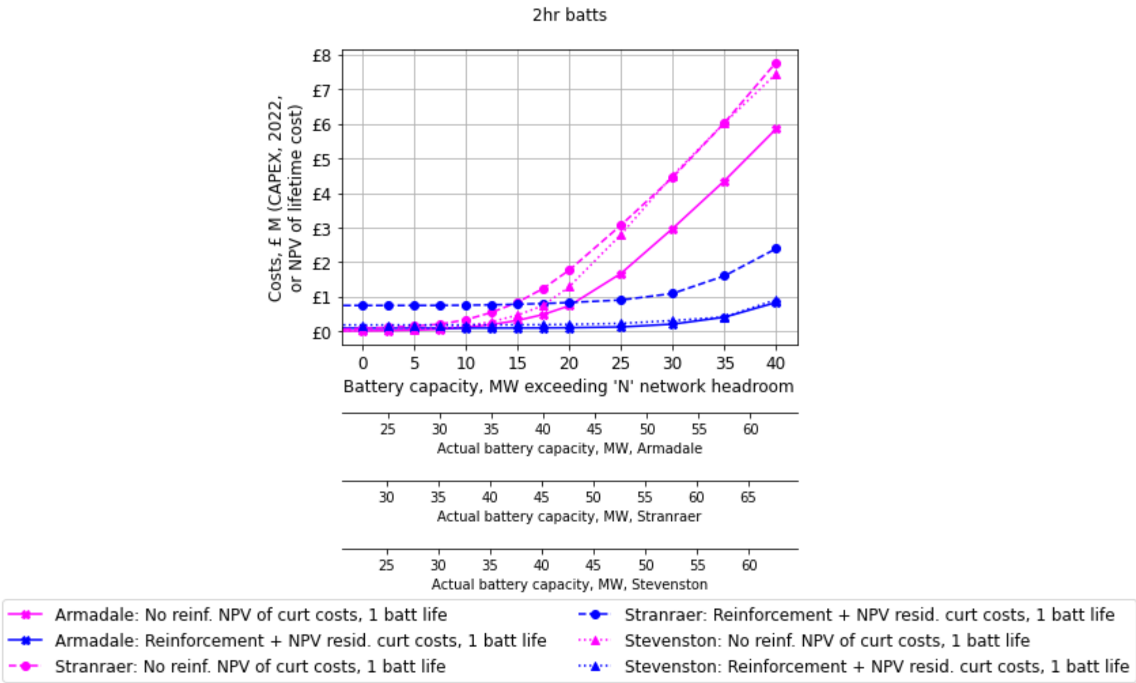


Figure 120 Costs of "reinforce" and "do not reinforce" options, Armadale, Stranraer and Stevenston. 2-hour batteries, "1 battery lifetime scenario"

The graph shows a broadly similar pattern to that for Fairlie, Largs and Lochan Moor. Looking at the pink line, as in the previous chart for Fairlie, Largs and Lochan Moor: "do not reinforce" option costs begin at around zero for smallest batteries, reach £1-2 M at battery sizes ~ 20 MW in excess of network headroom. However, for larger battery sizes, the increase in curtailment costs proceeds rapidly with increasing battery capacity.

There are also a few differences with regard to the "reinforce" option's costs, shown in the blue lines. Stranraer, having a much longer branch length than the Stevenston and Armadale, has significantly higher reinforcement costs (~ £800k, also similar to those of Fairlie, Largs and Lochan Moor); Stevenston's costs (~ £200k) are much closer to those of Armadale (~ £100k). Secondly, as larger battery sizes are modelled than for Fairlie, Largs and Lochan Moor, the effect of residual curtailment costs is apparent in increasing the "reinforce" option's costs (blue curve), as battery size increases, especially at the largest battery sizes.

As one goal of this piece of work is to find the conditions under which "network reinforcement" would be a higher or lower overall cost option than "no network reinforcement", the following sub section looks at larger scale graphs, to seek the range of battery sizes for which the different options would be "lowest overall cost".

8.4.2. Where is network reinforcement a lower-cost option?

Figure 121 below shows a summary of the key charts for all six locations. The top row (a) and (b) for Fairlie, Largs and Lochan Moor; the lower row (c) and (d) for Armadale, Stranraer and Stevenston.

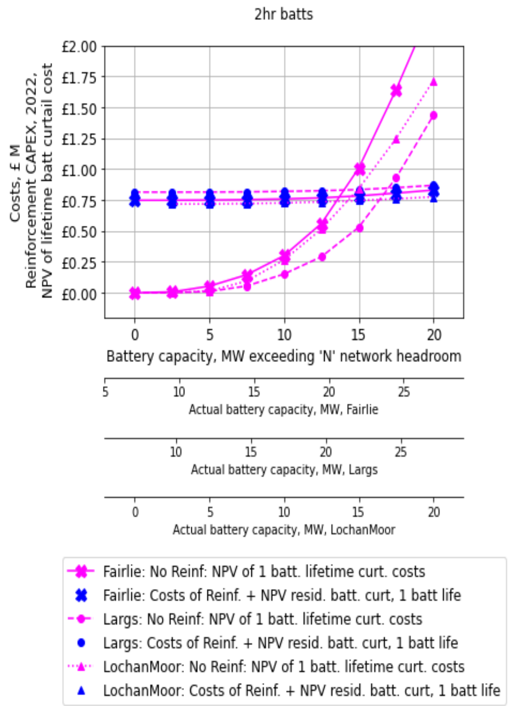
The patterns of all charts are remarkably similar. Charts (a) and (c) show the lowest curtailment costs 2-hr batteries, 1-lifetime scenario, and charts (b) and (d) the highest (4-hour batteries, 4-lifetime scenarios). The battery sizes at which the costs of "reinforce" and "do not reinforce" options are equal, lie between 2.5 and 17 MW ***in excess of network headroom***, i.e. exceeding the network capacity, after allowing for likely "worst case" use of the network by other connected demands and generation on that 33kV circuit. These values are tabulated in Table 61. Actual battery sizes range from 9 MW to 42 MW, as shown in Table 62. All charts are appended in Chapter 8 Annex 6.

Table 61 Battery sizes, **in excess of network headroom**, at which projected accosts are equal, for "reinforce" and "do not" reinforce" options

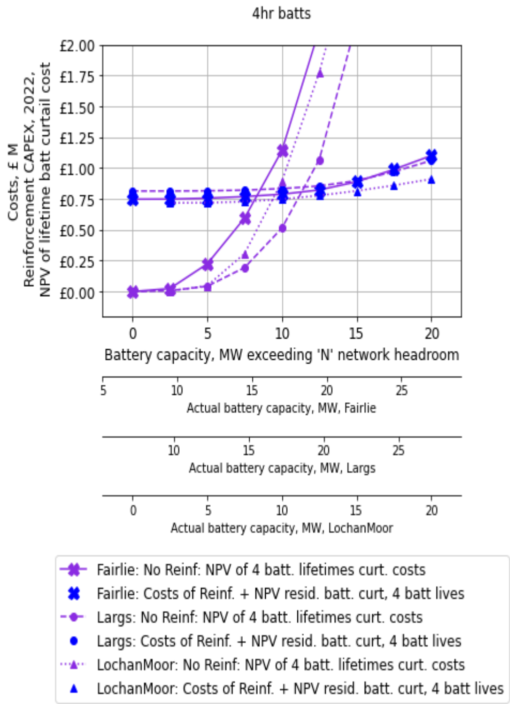
Location	Battery size, in excess of network headroom, at which "Reinforce option" costs equal "do not reinforce" option costs			
	1 lifetime		4 lifetimes	
	2 hour batts	4 hour batts	2 hour batts	4 hour batts
Fairlie	13 MW	11 MW	12 MW	8 MW
Largs	17 MW	13 MW	14 MW	12 MW
Lochan Moor	14 MW	12 MW	12 MW	9 MW
Armadale	10 MW	7.5 MW	5.5 MW	2.5 MW
Stranraer	14 MW	12 MW	10 MW	7 MW
Stevenston	10 MW	7.5 MW	5 MW	2.5 MW

Table 62 **Actual battery sizes**, at which projected costs are equal, for "reinforce" and "do not" reinforce" options

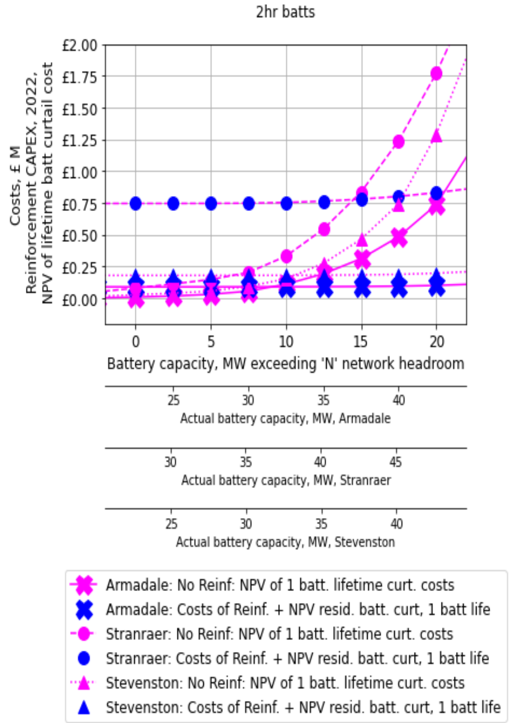
Location	Actual battery size at which "Reinforce option" costs equal "do not reinforce" option costs			
	1 lifetime		4 lifetimes	
	2 hour batts	4 hour batts	2 hour batts	4 hour batts
Fairlie	20 MW	18 MW	19 MW	15 MW
Largs	24 MW	20 MW	21 MW	19 MW
Lochan Moor	14 MW	12 MW	12 MW	9 MW
Armadale	33 MW	30 MW	28 MW	25 MW
Stranraer	42 MW	40 MW	38 MW	35 MW
Stevenston	33 MW	30 MW	28 MW	25 MW



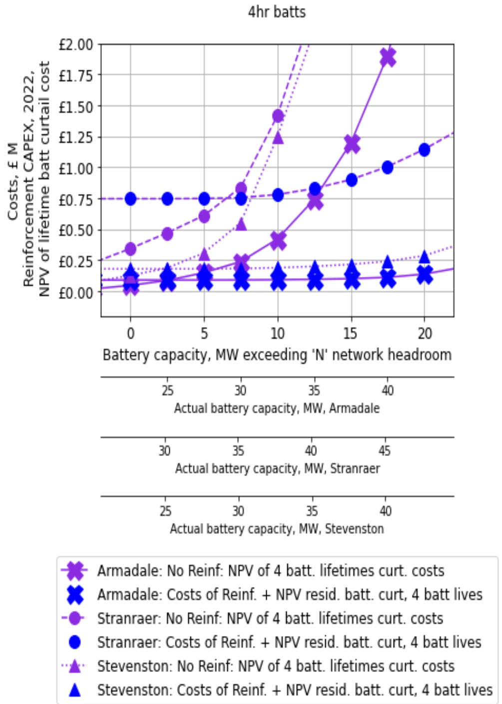
(a) Fairlie, Largs, Lochan Moor: 2hr batteries, 1 lifetime scenario



(b) Fairlie, Largs, Lochan Moor: 4hr batteries, 4 lifetime scenario



(c) Armadale, Stranraer, Stevenston: 2hr batteries, 1 lifetime scenario



(d) Armadale, Stranraer, Stevenston: 4hr batteries, 4 lifetime scenario

Figure 121 All locations: costs of "reinforce" and "do not reinforce" options, larger scale plots

For smaller battery sizes than those tabulated in Table 61 and Table 62, "do not reinforce" is projected to have the lowest overall cost. For larger battery sizes, reinforcement is projected to be a lower-overall-cost option.

Factors favouring "do not reinforce" option include: relatively high cost of reinforcement, and low curtailment costs: shorter duration batteries, a "1 battery lifetime" scenario, and network flows more accommodating of a battery, as discussed in the previous chapter. As seen here, out of the three single-feeder locations, which all have similar reinforcement cost, the "do not reinforce" option is favourable, up to larger battery sizes, at Largs – a location of moderate generation-dominated network flow - than at Fairlie or Lochan Moor, where network flows are more highly generation-dominated and curtailments occur more often.

Conversely, "reinforce" option is relatively favourable starting at smaller sizes of batteries at the two locations (Armadale and Stevenston) with much shorter feeders and thus lower projected reinforcement costs. This analysis finds that the effect of Armadale's generally lower curtailment costs – having more balanced network flows than demand-only Stevenston – which would favour the "do not reinforce" option, is cancelled out by its lower reinforcement costs (favouring the "reinforce" option) compared to Stevenston's, and the results at these two sites are very similar.

The significance of these results is discussed in the following section.

8.5. Discussion

8.5.1. Inherent uncertainties in these analyses

The exact values of the above costings – of both network reinforcement, and of whole lifetime battery curtailment costs - should all be viewed with some caution, as there are significant uncertainties with respect to some of the data, especially of current network reinforcement costs and future wholesale electricity trading prices.

However, even with different values of reinforcement costs, the same pattern of results would be expected: higher or lower reinforcement costs would make reinforcement an attractive option for larger, or smaller respective battery sizes, than those found in this analysis.

Similarly, different patterns of future wholesale price and price volatility, compared with those of 2022, would naturally affect the forthcoming battery revenues, and future costs of battery curtailment. Less volatile future wholesale prices would reduce battery "revenue forgone" from curtailment (though may also be detrimental to battery project viability), and so curtailment costs would rise less steeply with increasing battery size. Nevertheless, the generic pattern of results is considered robust, despite these considerable uncertainties.

8.5.2. Potential other scenarios and locations

The work above considers a single very specific reinforcement scenario: reinforcement of a single OHL, by the same capacity of an existing one, ~ 20 MVA. For scenarios of larger batteries, reinforcement of greater than ~ 20 MVA capacity would be cost-effective for a greater range of battery sizes, particularly at locations of short feeders where such reinforcement is relatively inexpensive.

A scenario not investigated was a reinforcement *of higher capacity*, partly because of lack of available cost data. Such a scenario may increase the cost of the reinforcement, though possibly by only a modest amount, as many fixed project costs would not change. Such an action would reduce or remove the costs of "residual battery curtailment costs after reinforcement". However, the "residual curtailment costs after reinforcement" are fairly insignificant in some locations, and where these residual curtailment costs do have significance, they are for batteries *significantly oversized* compared to current network capacity, and also of longer, 4 hour, duration. This suggests that oversizing reinforcement capacity would be of limited financial benefit, unless it could be done at little additional cost compared to a "same capacity" reinforcement, and even then, only for very large batteries. A "high failure rate" scenario would increase projected benefits of additional network capacity, and a "low failure rate" scenario would reduce such benefits. Clearly, installation of additional network capacity would bring wider benefits for possible future network connectees.

This work assumes that no reinforcement of GSP transformers or other infrastructure would be needed. In the event that other infrastructure is needed, clearly reinforcement costs would be higher, and "do not reinforce" options would be lower cost up to larger battery sizes. This work also considers that, at the 2-OHL locations, battery flows may route to GSP via the 11kV bus. Such additional flows may shorten the lifetime of the 33/11kV transformer and other equipment. If such flows would not be possible (or allowed), then clearly curtailment costs would be much higher, and reinforcement would appear relatively more favourable.

8.5.3. Potential use of this analysis in network planning

If this analysis or similar is to be used in network planning, this work illustrates some of the complexity of such decisions. Even where the capacity (MW) of battery projects is known, registers for future projects such as [223], [228] tend to have little information on the duration of batteries. The analysis above shows that even a difference between 2 and 4 hour duration of a battery makes a significant effect on curtailment costs, and potentially, if used, reinforcement decisions.

Far harder to ascertain would be a business model of the battery (or other storage asset), even over the short term, let alone over the projected 40 year lifetime of a network asset, given the much shorter lifetime of the batteries themselves. Longer term storage assets, such as pumped hydro schemes, having lifetimes closer to those of network assets than batteries, may be easier to plan for, in this respect. Furthermore, the development of both physical and financial infrastructure of energy networks, and expected further cost reductions for storage assets, are likely to provide new opportunities and incentives for different behaviour of batteries and other flexible assets, adding further uncertainty to any future projections.

Nevertheless, there are some clear findings from this work which may aid network planners and regulators. First of all, the fact that batteries can be oversized with respect to network capacity , and up to significant sizes suffer little curtailment costs, as discussed in the previous chapter, is significant. This work finds that such curtailment costs would be lower than the projected reinforcement costs, up to batteries of significant sizes. Batteries oversized with respect to network headroom of between 2.5 MW (Stevenston and Armadale, 4hr batteries, 4 battery lifetimes scenario) and 17 MW (Largs, 2 hour batteries, 1-lifetime scenario) were found to have projected curtailment costs which did not exceed costs of reinforcement. Projected capacities of batteries themselves, at which curtailment costs would not exceed reinforcement costs ranged from 9 MW (Lochan Moor, single-OHL site, no spare capacity) to 42 MW (Stranraer, 2-OHLs, 28 MW of network spare capacity).

While a more accurate analysis might find that “lowest cost” battery sizes smaller than above, for example if other network metrics (such as fault level, or voltage) mandate stricter limits on battery size, these figures nevertheless suggest that sizeable batteries could be accommodated.

8.6. Another approach to estimating the cost of reinforcement: the cost of *bringing forward* an investment

It is assumed that the renewal or replacement of an asset would provide an opportunity to increase the capacity of that part of the network at much lower cost than installing an altogether new piece of infrastructure / equipment, or replacing equipment which is still serviceable.

It is believed such a scenario to be particularly likely to hold for installation of OHLs, because such installations have considerable costs other than for material for the conductor, such as civils work, project management costs, and potentially costs of securing Planning approval.

If one can assume that renewing an asset – especially and overhead line - provides an opportunity to increase its capacity at relatively little additional cost, then it makes sense to consider whether and when replacement of the asset would have been expected in the absence of the battery. This section considers the costs of *altering the time* at which a reinforcement would be performed.

This section makes use of methodology of the Distribution Connection and Use of System Agreement (DCUSA) which considers the effect of altering the date at which a reinforcement would be done, albeit for a different purpose. The DCUSA-stipulated methods for enumerating Distribution Use of System (DUoS) charges for a connectee at EHV level involve estimating the effect the connectee will have on the date that reinforcement will be needed. Each DNO uses one of two methods, Forward Cost Planning (FCP) [175] or Long Run Incremental Cost (LRIC) [174], for this calculation. Both cost-calculation methods make assumptions about when network reinforcement will be needed, in the absence of the connectee. These "date-to-reinforcement" estimations are based on projections of future network loading, and the date at which overall loading will rise to a network limit, triggering reinforcement under a "base case" scenario, i.e. in the absence of the connectee. The presence of the connectee is likely to move the date of reinforcement either forward (sooner) if the connectee's actions increase overall network flows (e.g. add demand to a demand-dominated circuit, or generation to a generation-dominated circuit), or to delay the date of reinforcement if the connectee reduces overall network flows (e.g. adding generation to a demand-dominated circuit). The cost of the time difference in reinforcement work is enumerated as the difference in Net Present Value of the reinforcement work, at "base case" (without the connectee, original timescale) and “new case” (with the connectee, altered timescale).

A further approach to deciding a “base case” of when network investment would be needed could be based on asset age, assuming assets would need replaced when they reach the end of their lifetime (e.g. 40 years).

Costs of bringing forward an investment is calculated using DCUSA formulae

$$\Delta\, Cost(any\ project) = NPV(new\ case) - NPV\ (base\ case) \tag{8.21a}$$

So, $$\Delta\, Cost\ (total\ capital\ cost) = NPV\ (new\ case) - NPV\ (base\ \ case) \tag{8.21b}$$

Defining

$$y(base\ case) = number\ of\ years\ to\ reinforcement(base\ case) \tag{8.22}$$

$$y(new\ \ case) = number\ of\ years\ to\ reinforcement(new\ case) \tag{8.23}$$

And $$r = annual\ rate\ of\ interest$$

Where Net Present Values at “new” and “base” timescales are:

$$NPV(new\ case) = \frac{Cost\ of\ Reinforcement\ Solution}{[1+r]^{y(new\_case)}} \tag{8.24}$$

and

$$NPV(base\ case) = \frac{Cost\ of\ Reinforcement\ Solution}{[1+r\ ]^{y(base\_case)}} \tag{8.25}$$

So,

$$\Delta\, cost = Cost\ of\ Reinf.\left[\frac{1}{[(1+r)^{y(new\_case)}]} - \left(\frac{1}{[(1+r)^{y(base\_case)}]}\right)\right] \tag{8.26}$$

Rearranged as

$$\Delta\, cost = \frac{Cost\ of\ reinforcement}{[(1+r)^{y(new\_case)}]}.\left[1 - \left(\frac{(1+r)^{y(new\_case)}}{(1+r)^{y(base\_case)}}\right)\right] \tag{8.27}$$

$$\Delta\, cost = \frac{Cost\ of\ reinforcement}{[(1+r)^{y(new\_case)}]}.\left[1 - \ (1+r)^{\Delta y}\ \right] \tag{8.28}$$

Where $$\Delta\, y = y\ (new\ case) - y(base\ case) \tag{8.29}$$

So in the event a reinforcement is done earlier than originally intended:

$$y(new\_case) < y(base\_case) \qquad \Delta\, y < 0 \qquad \Delta\, cost > 0 \qquad (8.30)$$

And if a reinforcement can be deferred:

$$y(new\_case) > \; y(base\_case) \qquad \Delta\, y\, > 0 \qquad \Delta\, cost < 0 \qquad (8.31)$$

Table 63 shows the costs of performing an example piece of reinforcement work, costing £1000, this year, and 1, 5, and 10 years in the future. This table also shows, for each case, the cost of bring this work forward to the present year. All values are based on the above formulae, a discount rate of 3.93% p.a. [84] and an asset life of 40 years.

Table 63 NPV of capital costs of a £100k network reinforcement, at future dates, and the costs of bringing the work forward to the present year.

		NPV Cost of reinforcement work			
Years to future reinforcement work – "base case"		**0 years** (i.e. now)	**1 year**	**5 years**	**10 years**
Total capital cost of reinforcement	**Net Present Value of the capital cost of reinforcement**	**£100 k**	£96.2 k	£82.5 k	£68 k
	Cost (NPV difference) of bringing reinforcement work forward to the present year (0 years ahead)	**£0**	£3.8 k	£17.5 k	£32 k

Thus, with the above financial parameters, the cost of bring a project forward by one year is just under 4 % of the project's total capital cost (the cost of project execution at the present year). If considering moving a project forward 5 or 10 years, the cost of the early reinforcement would be 18% or 32% of the project cost, respectively.

This approach is not progressed further here, because more detailed information about costs, and the additional costs of reinforcing with a line of greater capacity, or indeed, adding an additional line (or transformer) to an existing project, are not available. However, this approach is considered worth continuing if such costings were available.

[84] The discount rate is taken to be the "Weighted Average Cost of Capital (WACC). The value used here is "WACC allowance (vanilla)", as applicable to DNOs, quoted on page 60 of the Ofgem's 2022 RIIO-ED2 Final Determination, Finance Annex [68]

Such costs – if they were available - may be more relevant than overall reinforcement costs – and potentially be better comparisons than full reinforcement costs, against which to consider battery curtailment costs.

8.7. Who pays, and who should pay?

The first part of this section, subsection 8.7.1, discusses the current apportionment of costs, both of battery curtailment, and of network reinforcement. The subsection ends with a discussion on whether or not these current arrangements encourage a "lowest overall cost" approach. Subsection 8.7.2 discusses which parties, potentially, "should pay".

8.7.1. Who pays? Current cost apportionment

This section considers who bears, or would be likely to bear, the costs of battery curtailment and network reinforcement.

As stated at the beginning of this chapter, an ideal arrangement is classically considered to be one in which total costs, including those of battery curtailment and network reinforcement, are as low as possible. However, it is important to consider that such costs are often borne by different parties.

The Distribution Connection and Use of System Agreement (DCUSA) v.15.4[85] document, Schedule 22 Common Connection Charging Methodology (CCCM) [253] sets out the rules governing a developer's share of any costs, which are discussed in the following subsections. Storage developers are treated as generators for the purposes of network charging.

8.7.1.1. Costs of curtailment: present and possible future

At present, costs of curtailment for distribution-connected assets, connected under a flexible or non-firm connection, are borne entirely by the connectee, in this case, the battery owner. A battery owner would also be liable for the costs of the control unit – which limits the import and export flows - at their own premises. Depending on the type of flexibility scheme or

[85] The rules changed following the Access and Forward Looking Charges Significant Code Review [247] in 2022. Earlier versions of the DCUSA document have different cost apportionments.

option[86], costs of the flexible connection control or management unit(s) may be borne by the developer (in this case, the battery owner), the DNO, or shared between scheme participants [253] paragraph 1.40 - 1.41.

In its 2022 Final Decision on its Access and Forward Looking Charges Significant Code Review [247] [Access SCR - Final Decision page 73-74] Ofgem states that flexible connections will continue to be an option for connecting customers (small users excepted) in locations where reinforcement is required. However, the distribution network operator will set curtailment limits, will state these limits in connection offers, and will need to abide by those limits, if necessary, by procuring flexibility services. Furthermore, Ofgem regards non-firm arrangements as generally an interim solutions, and now requires DNOs to set end-dates, after which connection will be made firm. Exceptions apply where a customer has not requested a firm connection, or does not wish to pay towards reinforcement costs exceeding the High-Cost-Project Threshold[87].

However, further policy changes may alter this situation, for example, in a situation where a DNO decides (or is required) to offer a "local flexibility service", in which it would pay a battery (or other provider) to limit its activity to times to avoid network congestion. The costs of curtailment – for a limited range of battery sizes - could be used as a starting point for estimating suitable prices of a "local flexibility service".

In such a situation, the costs of funding the flexibility service would be borne by the DNO. Under current arrangements, the DNO would raise them through Distribution Use of System (DUoS) network charges, which are levied on all customers.

[86] The Energy Networks Association, and DNO SP Energy Networks describe different flexible connection options: timed connections, export limiting devices, local management schemes, operational tripping schemes (which may be located at or distant from a customer's site), and, in areas with multiple or complex constraints, an Active Network Management scheme. [238], [239]
[87] £200/kW for generation and storage projects, and £1,720/kVA for demand projects [253] para. 1.16

8.7.1.2. Costs of reinforcement: the rules. Who pays?

Overview

Network owners are obliged to make connection offers to prospective developers. Where there exists plentiful capacity, such connections should be straightforward and low cost to arrange.

However, when there is insufficient network capacity on the network to accommodate the additional network flows of the connectee, the network connection process is more convoluted.

The traditional approach would be to offer the applicant a firm connection. The applicant (i.e. the developer) would normally pay towards the cost of the reinforcement work that their application triggers, depending on circumstances. Such a connection will also involve a delay, until the reinforcement can be performed. More recently, flexible connections are a way for applicants to get cheaper and quicker connections, as discussed in the previous chapter, but they must tolerate curtailment.

As set out in [253], developers of generation or energy storage projects are required to pay a share of the costs of any reinforcement of the network *at the same voltage level as the voltage level to which the generator or battery connects, unless other exceptions take precedence.* (DCUSA paragraph 1.18, illustrated by Examples 14 and 16, and referred to in Glossary "*Generation Connection"*). The liability for costs is summarised in Additional costs may also be due from a developer, if the developer connects to a piece of network, which was reinforced within a Prescribed Period, and the reinforcement was funded in part or in full by a previous developer. Under some circumstances, a developer which pays full costs of a reinforcement which it triggers may be entitled to a later rebate, in the event that a future customer connects to those assets (DCUSA paragraphs 1.44-1.47).

In the event that a development triggers reinforcement work to the transmission network, the developers may be required to pay towards such works too. (DCUSA paragraphs 1.73).

Table 64.

Additional costs may also be due from a developer, if the developer connects to a piece of network, which was reinforced within a Prescribed Period, and the reinforcement was funded in part or in full by a previous developer. Under some circumstances, a developer which pays full costs of a reinforcement which it triggers may be entitled to a later rebate, in the event that a future customer connects to those assets (DCUSA paragraphs 1.44-1.47).

In the event that a development triggers reinforcement work to the transmission network, the developers may be required to pay towards such works too. (DCUSA paragraphs 1.73).

Table 64 Summary of a DNO's and a battery developer's liability for network reinforcement costs

<table>
<tr><th>Battery connection voltage</th><th>Reinforcement costs apportioned between battery developer and DNO</th><th colspan="2">Reinforcement Costs borne by DNO in full</th><th>Reinforcement costs borne by battery developer in full</th></tr>
<tr><td>LV</td><td>LV network "Minimum scheme" reinforcements</td><td>HV & EHV reinforcements
HV / LV substation, other than circuit breakers at LV side</td><td rowspan="4">Costs of "Enhanced Scheme" connection in excess of "Minimum scheme", if made at DNO's request</td><td rowspan="4">Costs of "Enhanced Scheme" connection, in excess of "Minimum Scheme" if made at developer's request
Assets for sole use of battery development
Reinforcement costs exceeding the high cost threshold of £200/kW
Speculative projects</td></tr>
<tr><td>HV
e.g. 11kV</td><td>HV network "Minimum scheme" reinforcements
HV-side circuit breakers of EHV / HV substation</td><td>EHV network
EHV / HV substation, other than circuit breakers at HV side
England and Wales only:
132kV / EHV substation
132kV network</td></tr>
<tr><td rowspan="2">EHV
e.g. 33kV</td><td>EHV network "Minimum scheme" reinforcements</td><td>England & Wales only
132kV network</td></tr>
<tr><td>England & Wales only
EHV-side circuit breakers of 132kV / EHV substation</td><td>England & Wales only
132kV / EHV substation – other than EHV-side circuit breakers</td></tr>
</table>

Cost apportionment

For reinforcement costs which are to be apportioned between the DNO and the developer, DNOs use two different "Cost apportionment factors (CAFs)" to determine the proportion of the costs of reinforcement which the new connectee must pay: the Security CAF and the Fault Level CAF. The DNO uses the higher of the two CAFs.

$$Security\ CAF = \frac{Required\ capacity}{New\ network\ capacity} * 100\% \tag{8.32}$$

(DCUSA paragraph 1.30)

$$Fault\ Level\ CAF = 3 * \left(\frac{Fault\ Level\ Contribution\ From\ Connection}{New\ Fault\ Level\ Capacity}\right) * 100\% \tag{8.33}$$

(DCUSA paragraph 1.31)

In both cases, the maximum proportion of costs which a connectee may be liable for is 100%.

Scenarios of a battery developer's liability for costs

Table 65 shows some examples of cost apportionments, with different scenarios of reinforcements.

Table 65 Developer's cost share of apportioned reinforcements

Scenario 1	**DNO installs exactly the additional capacity needed**			
Extra capacity needed by battery	5 MW	10 MW	15 MW	20 MW
Extra capacity installed	5 MW	10 MW	15 MW	20 MW
Cost apportionment factor	100%	100%	100%	100%
Scenario 2	**DNO installs – at its own choice - additional 20 MW of capacity to EHV line**			
Extra capacity needed by battery	5 MW	10 MW	15 MW	20 MW
Extra capacity installed	20 MW	20 MW	20 MW	20 MW
Cost apportionment factor	25%	50%	75%	100%

Smaller batteries, connecting at HV level, would not be liable for reinforcement costs at EHV level, or of primary substations, which they may trigger, though they would be liable for some of the costs, including for their sole use, and of circuit breakers. Larger batteries, connecting at EHV level, would be liable for a share of EHV reinforcement costs. The actual sum they would pay would depend on the type and capacity of reinforcement that is necessary, and the engineering solution that the DNO chooses.

8.7.1.3. Do these arrangements encourage a lowest cost approach?

While a "lowest overall cost" arrangement may be regarded as an ideal, enumerating or recognising such a situation is not straightforward. Costs of generator (or storage) curtailment and network reinforcement are borne by different parties, and their values are generally not in the public domain. Furthermore, the approach used here, in seeking costs over the whole lifetime of the asset, is subject to many inherent uncertainties. Nevertheless, this section provides generic comments on this matter.

Battery connections at HV level, which would normally be for smaller batteries, would not bear the cost of EHV reinforcement they might trigger. Such a situation might encourage them to request a firm connection, whose reinforcement cost would exceed the cost of curtailment. Such a situation would not appear to be a lowest cost solution.

In the case study locations investigated in this work, a small (< 5 MW) battery connecting at HV level, and triggering reinforcement at EHV level, would only appear to be pertinent to one location, export-dominated Lochan Moor, which has no spare capacity for further exports at all. At the other locations, it could potentially occur in the future, if further developments were to connect and use up more of the currently -available network capacity.

For larger batteries, connecting at EHV level, a battery developer would have liability for a share of network reinforcement at EHV level. The developer's share of the bill depends on the capacity required by the battery, and the DNO's chosen reinforcement. For a large battery capacity requirement, which would use most or all of the capacity of a new connection, the developer would pay the correspondingly major share of the reinforcement cost. Thus, it would only make sense for the developer to choose this option if its share of reinforcement costs were lower than projected curtailment costs. This would be more likely in the case of large batteries, sized well in excess of network headroom, and / or at locations where the necessary reinforcement is relatively inexpensive, such as Armadale and Stevenston, as discussed in Section 8.4. For a smaller battery, the liability depends on whether the DNO reinforces to just enough capacity ("Minimum Scheme") or larger capacity ("Enhanced Scheme").

Thus, there are some cases in which a developer would bear a minority of reinforcement costs, such arrangement may encourage the developer to seek a firm connection, in which overall reinforcement costs exceeds projected curtailment costs.

There are other cases in which a developer would bear most or even all costs associated with network reinforcement. Such a developer would only proceed if these costs were less than projected curtailment costs, and indeed, if its business model could withstand these costs. These costs provide a strong incentive to a developer to move the project to location on the network where there is capacity: indeed, connection charges are, by design, a strong locational signal for developers of generation and storage projects, and the only one for HV or LV-connecting customers[88]. Such a move would appear "lowest cost" approach. However, with increasing demands for connections, for different purposes, fewer locations with spare capacity are available. Figure 122 shows an excerpt from SPEN Distribution, showing that most GSPs and EHV lines in their Scottish area are classed as "red" i.e. with minimal if any spare capacity.

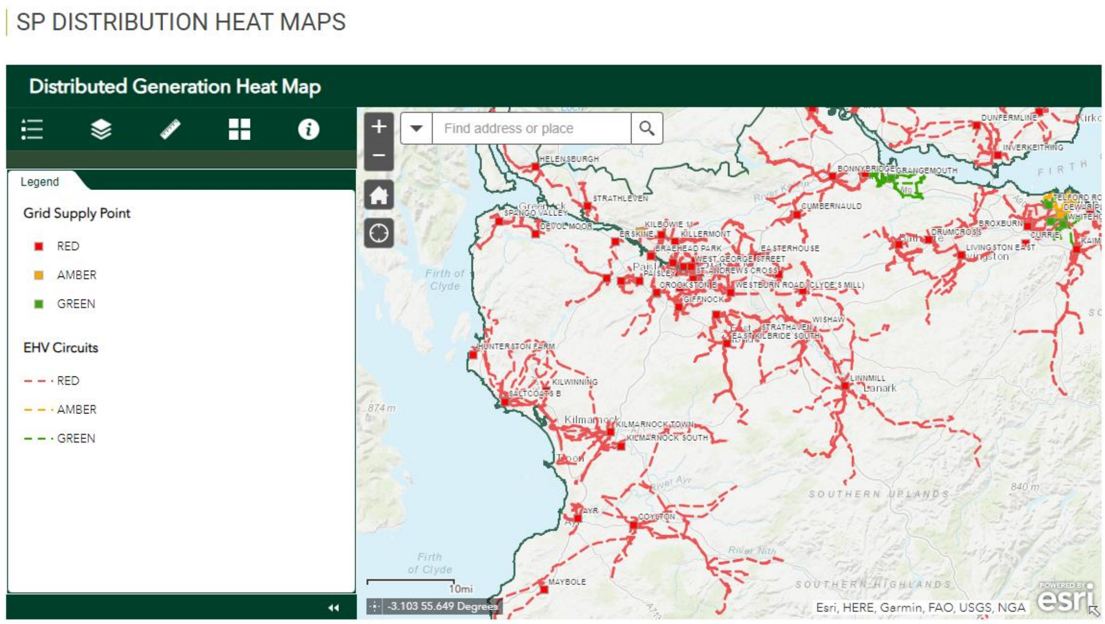


Figure 122 Excerpt from SP Distribution (Scottish area) "Heat Map", 23 October 2024, showing Grid Supply Points and EHV circuits [254] [SPD Heat Map - SP Energy Networks] for generators

The following subsection discusses what approach and partition of costs perhaps *should* apply.

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[88] EHV-connecting customers receive bespoke Distribution Use of System charge, which, alongside connection charges, may provide a locational signal to developers.

8.7.2. Who *should* pay? Is a "lowest overall cost" approach the best one? Other considerations

The question of which party/ies ought to pay for network reinforcement starts in engineering but reaches into other disciplines, and there is no single answer.

If one regards storage assets as an important addition to our electricity system, one which can provide flexibility and a range of services which will be increasingly needed as our system decarbonises, then one may take the view that batteries and other storage assets should be enabled to connect without bearing the full cost of any reinforcement they may trigger. Even if the batteries *are* engaged in wholesale trades, they *could* provide other services, if incentivised. Thus, their very presence can provide DSOs and the ESO options for local and system-wide balancing and other necessary services, at a time of need. Akin to paying generators for participation in the Capacity Market, "just in case" a situation of generation inadequacy arises in the future, encouraging deployment of batteries may be justifiable to add further security to our system. Furthermore, large-scale roll-outs of many "novel" manufactured goods has brought down their prices, as is seen with not only with lithium ion batteries at present, but recently with other technologies such as solar PV and LED lighting. The availability of lower-cost batteries in future could be viewed as a goal so desirable as to justify some expense – in the form of subsidised network connections – at present.

Ofgem cites stakeholder evidence of prospective developers' responses to liability for network reinforcement charges [255] page 25]. By far the most common response was project abandonment. A much smaller share of respondents proceeded, at either original or reduced capacity, or re-located the project. While the Ofgem-cited survey was within a different industry sector, EV charging stations, records from a working group on a major network charges review found similar responses from different types of stakeholders, including of battery projects, which are summarised in Chapter 8 Annex 7. Thus, it would not be surprising for a battery developer to abandon a project if significant connection charges would be required. While it is worth noting that since the aforementioned stakeholder consultations, the 2022 Access SCR decision [247] has reduced developers' liability for payment towards network reinforcements[89], the general principle that any significant connection charges tends to deter projects is not expected to be changed. Though battery business models are out of

[89] Previous arrangements are described in an earlier version of the DCUSA Schedule 22, available at [286]

scope of this analysis, it seems obvious that one battery project which pays reinforcement charges might struggle to compete, for example on prices of service it might provide, with a similar battery project elsewhere not burdened with such costs. This situation, given lack of network capacity in many areas, could favour arguments for socialising costs of network reinforcements, to encourage battery deployment.

Conversely, one could regard batteries as legitimate but self-serving private business interests, which should be rewarded for any services they provide, but which should bear the costs, in full, of any costs that they cause to electricity networks. This view is found, for example, in [256] with reference to wind generators. Especially if batteries are engaging in wholesale trades which do not align with network needs, one could argue there is no reason even to seek a "lowest overall cost" solution, especially understanding that reinforcements funded by DNOs are currently funded from bill-payers, who have varying abilities and inabilities to pay.

As the ENA states in its "Tactical solutions guidance" regarding battery connections [102], discussed in the previous chapter, agreed battery connections in some areas have removed much or even all network capacity, leaving little or none for other future or current users such as new generators, or new or increasing demands. Analysis in Chapters 6 and 7 showed that battery activity does not always align with network needs, and it cannot be assumed that network capacity granted to a battery can safely be "shared" with other network users. Considering that Britain's Net Zero pathway will include electrification of much of our heat and transport, and further additional low-carbon generation are, both of which are likely to require additional distribution network capacity in some areas, and given the delay and cost of building reinforcements, there is some justification for the ENA's view that excessive volume of battery connections may even delay our progress to Net Zero. Clearly, there is a major problem with the volume of demand for new connections, and the time required to build them.

There are further questions. Would reinforcement, triggered by a battery development, bring wider benefit to other network users? Clearly, if the battery needs to use all the additional capacity, there would not be wider benefit, but in a scenario of a DNO building additional capacity beyond that needed by the battery, such capacity would be available for other users, if there are any located nearby.

A related question is whether a DNO should prioritise a battery developer's connection request over requests of other network users. A simple example considered here is the sizeable town of Largs, one of the case study locations, connected to GSP with only a single connection. Arguably, an engineering solution of greater benefit to DNO customers would be to install a second 33/11kV substation at the 11kV bus, with its own new 33kV OHL to GSP, in order to provide redundancy and increased security of supply to all 11kV-and-below-connected users. Analysis in the previous chapter assumed (at other case study locations) that such a solution would provide additional capacity to the battery, though slightly less than a bespoke OHL at its own connection point. Tactical guidance from the ENA [102], as previously discussed, is strongly of the view that reinforcement to avoid curtailment of storage assets under 'N-1' conditions would be a poorer use of resources than certain other network reinforcements for use by other users. In current conditions of resource constraints delaying construction of additional network, further reinforcement projects, such as for a battery development, will increase delays for others'.

And finally, returning to the system services that batteries can undoubtedly provide, their track record in provision of Frequency Response services is strong and clear. Batteries of duration of 1 – 4 hours can also be effective in "peak shaving", for example, of evening peak demands, which tend to last for a couple of hours. Such batteries could potentially contribute to utilisation of solar generation away from a few hours around midday to other times of greater demand. However, wind events tend to be longer in duration, many hours to a few days, as shown in Chapters 6 and 7. A short-duration battery cannot relieve export-dominated network constraints of such timescales, neither can they address the more challenging needs of inter-seasonal storage. Longer-duration types of storage exist, but not currently widely commercial available [257]. Even if minded to facilitate the deployment of batteries, it is important to consider their characteristics, and to be mindful of what services they can and cannot provide.

In short, two plausible but contradictory arguments have been presented with respect to the question of what kinds of cost apportionments should apply. These differing arguments would favour different approaches. This question of cost apportionment rests more with infrastructure policy than engineering, as it raises questions of what assets are desirable or indeed necessary to have on the networks, whether such deployment is better achieved through "central planning" or "market-led approaches", and which costs should be socialised and which borne by parties which cause costs. These are questions which this thesis can raise but not answer.

8.8. Conclusions: comparison of costs of curtailment with costs of network reinforcement

This chapter seeks to further address the research question of what mitigation might be appropriate, if battery actions do not inherently relieve network constraints. Building on the work of the previous chapter, a traditional approach, used in Transmission Network planning, is that an “ideal” amount of network would be that where overall costs are at a minimum, considering all costs borne by all parties.

8.8.1. Finding the “lowest cost” arrangements for the case study locations

First, it is not straightforward to compare costs of curtailment of a ten-year asset with those of a forty-year asset, especially where different financial parameters apply, and to the former, degradation in performance. Especially uncertain are future projections of curtailment costs, with expected changes in price patterns from year to year, and unknown long-term business plans of battery projects. Added to these uncertainties is the lack of publicly available data for network reinforcement cost, against which to compare curtailment costs.

However, the generic pattern of these results is considered robust, even though the actual battery capacities for “equal costs of ‘reinforcement’ and ‘no reinforcement’ options” may differ from those found here.

Across all case study locations, broadly similar patterns of results were obtained. For each location and scenario, there is a “curtail rather than reinforce” battery size, below which projected lifetime curtailment costs would be less than the cost of reinforcement (including residual curtailment costs not avoided by reinforcement).

In all six location case studies, considering a possible reinforcement of a single OHL, the “curtail rather than reinforce” battery size was in excess of “network headroom” (as defined in the previous chapter) at that location. Sizes of batteries up to which “do not reinforce” appears a lower cost option than “reinforce” varied from 2.5 MW to 17 MW in excess of network headroom, depending on location and scenario. The corresponding range in actual battery sizes varied from 9 MW (Lochan Moor, no spare export capacity, for 4hr batteries and assumed battery repowering) to 42 MW (Stranraer, 28 MW spare capacity, 2hr batteries, assumed no battery repowering). Locations of similar lengths of feeder to be reinforced had broadly similar results.

Factors favouring the "do not reinforce" option include high reinforcement costs, arising from long feeders. Transformer upgrades were not considered here, but if needed, they would considerably add to reinforcement costs and make such an option less attractive. A "do not reinforce" approach would also be favoured by a project in which batteries are of relatively low MW capacity and short duration, a short project lifetime, and locations with network flows that better accommodate additional battery flows, generally by having a mix of generation and demand. Unfortunately, costings for adding capacity to a reinforcement project are not available, which would help investigate location-bespoke solutions.

The converse of the above factors would favour the "reinforce network" option. Furthermore, if a battery-triggered reinforcement is regarded as a *shift in time* of an upgrade which was going to be necessary at some point even without the battery project, the cost is the *time value of the reinforcement CAPEX*s, which is lower than *the whole project cost* (for projects brought forward by a time interval shorter than the asset lifetime). Such a view would make reinforcement an attractive option for smaller batteries.

8.8.2. Considering whether charging arrangements encourage a lowest cost arrangement

The apportionment of reinforcement costs depends upon a number of project specific factors. In some cases, when a battery would trigger a reinforcement at a voltage level higher than the level at which it connects, the DNO would pay the bulk of the reinforcements costs. In other cases, namely reinforcement costs of the same voltage level as that of battery connection, many costs are apportioned between the developer and the DNO. Some costs are payable by the developer in full. Thus, developers of battery and other projects are strongly incentivised to locate in an area of spare network capacity – a lowest-cost solution in the short term, though arguably, "free-riding" on available network capacity [255]. However, locations of plentiful network capacity are increasingly scarce.

Evidence is presented by Ofgem and BEIS that liability for reinforcement costs is a major deterrent to project developers, who are more likely to abandon than proceed with such a project. Project-specifics are not available, but presumably this would apply even when network reinforcement may be a lowest-cost solution, if the project's business model cannot or chooses not to bear such costs.

Thus, in some cases, the developer is shielded from the reinforcement costs, and cost arrangement would encourage is seeking of a firm connection, even one where the reinforcement costs (borne by others) exceed those of lifetime curtailment. In other cases, liability for reinforcement costs would deter a project from going ahead, presumably, even in some cases in which network reinforcement could be the lowest cost approach. Enumeration of a "lowest cost solution" is subject to significant uncertainty. Design of network charges and apportioning liabilities is complicated – as evidenced by the several of years taken to conduct the Access and Forward Looking Charges Significant Code Review [247].

So, do arrangements encourage a "lowest cost approach"?

Sometimes yes, sometime no. There are inherent difficulties and uncertainties in costs over a long lifetime of a network asset, difficulties compounded by a lack of data transparency. While worth having regard for, the question of "what is a lowest cost solution?" needs to be considered alongside considerations of practicality, what kind of network we need, what kind of assets we need to be connected to it, and which parties can afford to pay.

8.8.3. Considering whether charging arrangements should encourage a lowest cost arrangement, and which parties should bear the costs of reinforcement.

Section 8.7.2 gives arguments for and against allocating cost-reflective portions of network reinforcement charges on battery projects which trigger reinforcements – which arguably should incentivise a battery project to choose the lower cost option out of "reinforce the network" or "do not reinforce". However, even cost-reflective apportionment of reinforcement charges may make a battery project unattractive or unviable; on the other hand, socialised network reinforcement charges fall on all DNO customers, who have varying abilities and inabilities to pay. Whichever party pays for reinforcement, the costs are likely to end up on consumers' bills, eventually, whether from DUoS charges, power prices, or costs of balancing or flexibility services.

A battery-triggered network reinforcement may bring benefits of additional network capacity, available to other users, in the event of the DNO implementing "Enhanced Scheme" reinforcement in excess of battery requirements, or the (not unlikely) scenario of the battery project ending during the lifetime of the asset. Such an investment may have value, if other generators, storage assets, or new or increased demands would need the increased capacity at that location. Conversely, a battery-triggered reinforcement might divert DNO resources away from other reinforcements of greater societal benefit, and thus delay their construction and installation of other projects.

A key question is: does the presence of battery storage assets on networks bring wider benefits? The above work shows that a battery, located in southern Scotland, and engaged in arbitrage, according to the pricing patterns of the 2022 case studies, would more often exacerbate network flows than reduce them. However, the presence of batteries can allow DNOs and the ESO to use their flexibility for ancillary and balancing services. Battery owners need to have a commercially viable business case, and may need some revenue from arbitrage – which would generally not have been helpful to networks, in Scotland, according to 2022 prices – in order to be present to provide services that do benefit networks. This chapter has enumerated some of the "cost" of connecting batteries to networks. This chapter cannot answer whether the "cost" of batteries engaging in arbitrage, is "worthwhile". Answering that question would require an examination of the value of batteries' current and future provision of flexibility services, together with possible alternative providers, if any, of such services. Such a piece of work would be valuable.

9. Chapter 9: Conclusions

Chapter summary

This chapter addresses all the research questions posed in Chapter 1. This thesis builds on a significant body of prior knowledge, but its findings are novel in several ways. There are many suggestions for further work. This chapter ends with recommendations to policy makers, regulators, the system operator and network owners.

This work addresses the research questions set out in Chapter 1, and has additional findings and recommendations to policy makers.

9.1. Research questions

9.1.1. Research question 1: What kinds of behaviours are foreseeable from short-duration batteries?

Batteries and other storage assets have a choice of income-generating activities, including provision of ancillary services, balancing actions (if called upon by the ESO), engagement in wholesale trades, and in some locations, provision of DSO flexibility services, which are described in Chapter 3. The more astute providers are likely to jump between revenue streams, sometimes within-day.

By the end of 2022, engagement in wholesale trades was competitive with ancillary services provision in terms of revenue for providers (Chapter 4, Section 4.10.3). The actions a rational battery would undertake, if engaged in wholesale trades, was simulated for three 5-week case study periods in 2022, using real price data. This study found that batteries would usually import at night, when electricity is usually relatively cheap, and would very usually export during a late afternoon or early evening, when prices were highest. During two of the three case study periods, on many days a second trade was often simulated: a morning export, and a midday import. On some days trades occurred at other times, particularly when price patterns were less regular (as described in sections 4.7.2 and 4.7.3).

Sensitivities for longer duration batteries resulted in broadly similar diurnal patterns, though longer duration batteries were active for more time periods of the day (Section 4.8.1).

Sensitivities for limitation of battery cycling to reduce degradation or to comply with warranty conditions found similar diurnal patterns of activity, but with less frequent trading overall. Increasing the round-trip losses in simulations also reduced the frequency of trades, as some potential trades were financially unviable (Section 4.7.4 and Annex 2 of Annexes to Chapter 4).

Real grid-connected batteries exhibited a mixture of actions, but “one cycle a day” and “two cycles a day” patterns were observed by some during parts of all the case study seasons (sections 4.9.2 - 4.9.4), though batteries had days of no or very low-power activity, and often imported or exported at lower power than full capacity.

9.1.2. Research Question 2: Are expected behaviours of short-duration batteries likely to alleviate of exacerbate network congestion and system needs?

Clearly, short-duration batteries can and do make a very valuable contribution to provision of ancillary services to the ESO, and flexibility services to DSOs, services which are likely to be needed in increasing volumes as the system decarbonises.

However, regarding network congestion, the results are mixed.

During some times, such as a cold snap in the middle of the winter case study period, the system-wide prices correlated well with network flows (e.g. Section 6.7.1). The actions of a self-interested battery, engaged in wholesale trades, would inherently reduce maximum demand flows by exporting during the late afternoon demand peak, and would charge up at night when demands are low. This behaviour would reduce demand-driven network congestion.

However, results during summer and autumn case study periods found the price pattern would encourage an additional midday import of electricity on many days. The case study locations, in southern Scotland, had a clear “one peak a day” demand pattern, with little or no reduction in demand flows in the middle of the day, presumably having little or no connected solar PV generation (e.g. Section 6.7.2). Thus, battery imports around midday would exacerbate demand flows, which were high for the time of year. Larger batteries could thus increase demand-driven network congestion, in the absence of any other renewable outputs e.g. from wind.

When comparing battery actions with wind generation, there were occasions when a large increase in wind generation was accompanied by a drop in wholesale price. However, more often, diurnal patterns of price continued, irrespective of wind conditions, which would incentivise a battery to engage in both imports and exports (e.g. Figure 44 in Section 5.3.1 & Chapter 5 Annex 1). Exports by a distribution-connected battery on any wind-dominated network would exacerbate congestion on that part of the network. Networks with high wind penetration are very common in parts of rural Scotland, and also exist in other areas of Britain. Such exports by a battery located in Scotland would also contribute to transmission congestion, and under present conditions, be likely to further necessitate curtailment of wind generation north of the B6 transmission constraint.

Battery imports during times of high wind would reduce network congestion, though, as found by previous studies in Northern Ireland and the USA [60], [95], high-wind events usually lasted much longer than the duration of short-duration batteries, so such battery imports would not be effective in reducing congestion beyond a small part of the high wind events' durations. Much longer-duration batteries or other types of storage would be needed for such a service, if one is desired. A brief inspection of likely incomes of batteries of different duration from wholesale trades found that incomes per kWh decreased with battery duration, as found previously by others [95]. It is likely that, if longer-duration storage is considered an important addition to the GB network, some other means of financial support will be needed.

In 2009, in the USA, Denholm and Sioshansi stated in [94]: *"Fundamentally, the problem with co-located wind / [energy storage] is that wind production and [wholesale electricity prices] are largely decoupled at current levels of wind penetration."*

This is the current situation in Great Britain.

Regarding the expected situation in a few years, with increasing penetrations of renewables, Denholm and Sioshansi's projection in [94] may also apply to GB: *"As the amount of wind [generation] increases, it will begin to drive electricity prices, resulting in lower [electricity] prices during periods of high wind, and higher prices during periods of lower wind. An optimally dispatched [energy storage] system will begin to more closely respond to wind patterns, so the operation of [energy storage, aiming to maximise its own revenue, or alternatively, aiming to increase wind penetration / reduce network congestion], will begin to converge."*

These simulated behaviours of batteries, in response to wholesale price variations, are not confined to storage assets: they could also be expected from other types of network users, including flexible generators and flexible demands.

9.1.3. Research question 3: Is a large-scale roll-out of batteries likely to facilitate or obstruct deployment of renewable / low carbon generation, and the electricity system's transition to Net Zero?

As with Research Questions 1 and 2,this work has found that a roll-out of batteries can be expected to have different effects, at different places, different times, and according to different realistic decisions taken by battery owners. These different effects, taken together, could both facilitate and impede renewable generation deployment and wider system decarbonisation.

Clearly, the ancillary, balancing and DSO flexibility services that batteries and other storage assets can provide are of enormous benefit to the electricity system, especially as it decarbonises, and can well complement higher penetrations of renewable generation. Furthermore, evidence from another jurisdiction [97]has found that batteries engaged in self-interested trades can complement outputs from solar PV.

However, this work has found that current price signals do not well reflect network and system needs under differing conditions of wind, nor even variations in demand patterns in locations where solar penetration is low. A rational battery would be incentivised to exacerbate both maximum import and maximum export flows in locations of high wind generation at times, especially where there is little or no solar generation. This is because system-wide price is often more sensitive to diurnal price variations than changes in wind output: times of high system prices occur, even when it is windy, encouraging a battery (and other price-sensitive generator) deliver power which would exacerbate any wind-driven export constraints. Conversely, a system-wide price dip is often seen around midday outside of winter and is probably caused, in part, by system-wide solar output. However, locations lacking solar generation tend to have little if any midday drop in demand, so a battery (or other flexible demand) encouraged to import around midday could exacerbate the largest imports.

Thus, in the absence of any other controls, and in a situation of network constraints and long connection queues in many parts of distribution networks, distribution-connected batteries, with firm connections, would require network capacity which could not be awarded to other future network users. This is not helpful in facilitating a renewables roll-out, or decarbonisation of the electricity system or wider economy.

As in Research question 2, these potential negative consequences could also be seen from actions of price-responsive generators and demands.

It is likely that this would not be the case in areas with solar rather than wind penetration, but that situation was not investigated in this work. Similarly, locations with their own hydro resources may show different results, which again were not investigated here.

9.1.4. Research question 4: If there are any negative consequences of battery deployment, what mitigation measures might be appropriate?

Option 1: Connect batteries with non-firm connections

This work investigated the effect of a non-firm connection on the incomes, from wholesale trades, of a battery on a constrained distribution network, in Chapter 7. This work found that batteries could be significantly oversized, compared to network capacity, before suffering significant financial penalty from uncompensated curtailments. The financial effect of curtailment was lower for shorter-duration batteries (2 hour) than for longer-duration batteries (4 hour), because in many cases, shorter-duration batteries can still complete most of their desired trades, even though, at restricted power, they require a longer time to do so. Networks with a relatively balanced mix of demand and generation (wind) generally could "tolerate" battery actions better than locations where flows were strongly either demand- or generation-dominated.

Thus, connecting batteries with a non-firm connection would appear to be a very promising approach to balancing their desire for a network connection and for network capacity for wholesale trades, and other users' needs for the network capacity.

Such an arrangement was found to have lower projected costs than traditional network reinforcement in some of the case studies, for some battery sizes, especially where longer feeders are projected to have higher reinforcement costs (Section 8.4). However such a calculation is complicated by the fact that curtailment and network reinforcement costs are borne by different parties (Section 8.7). , and that up-to-date costs of network reinforcement are not in the public domain (Chapter 8 Section 8.3.1).

These calculations were in a case of no other users in a curtailment queue. If there are multiple network users on the same network, all connected with non-firm connections, later connectees are more often curtailed, and suffer longer durations of network restriction and so greater financial impacts. This is the case with some wind generators, as described in [84].

Option 2: Locational pricing

The undesirable actions by batteries and potentially other network users described above would be in response to system-wide price signals, which sometimes do not well fit with power flows and network needs on a local, regional and home nation scale. Introduction of some kind of locational pricing is a consideration of the ongoing Review of Electricity Market Arrangements (REMA) [24]. Such a change would be likely to alleviate many of the above problems, and probably bring additional benefits, but would also have likely negative consequences.

One proponent of adopting locational pricing in GB, the UK's Energy Systems Catapult, argue that locational pricing, specifically its preferred nodal pricing, would "*encourage generators and providers of flexibility to locate and operate assets (e.g. generation or storage) efficiently, taking account of the real physical constraints in the network. Over time this is likely to lead to more efficient location of new resources and efficient expansion of the network. It will reward innovation and development of flexibility in locations where it is most valuable to the overall system"* [258]. Their arguments refer to academic theory, and the numerous power systems which successfully use locational pricing, whether zonal, such as the Nordpool trading area in Scandinavia [259], or nodal, such as the PJM power system in the USA [260]–[262].

However, detractors of locational pricing, such as consultancy Regen, argue a paucity of examples of locational pricing in grids *with large penetrations of inflexible renewable generation*, especially of large wind resources, windfarms which *inherently* tend to be sited remotely, rather than close to towns and cities, due to the large areas and consents such installations require. Regen argues that greater transmission capacity, rather than pricing revolution, would provide most efficient outcomes [263]. If locational pricing is implemented, expected periods of near-zero prices in renewables-dominated areas, such as the whole of Scotland, would render further generation deployment much less attractive, and compound business risk. Industry groups argue such risk would raise the cost of financing projects, costs which would have to be passed on to energy consumers, for example in higher prices of power or Contracts for Difference strike prices [264]. Any future efficiency gains from the introduction of locational pricing would therefore have to be considered together with its likely resultant costs. Furthermore, as renewables throughout GB, deployed and yet to be built, including those sited in Scotland, are essential to attain the UK's "Clean Power 2030" target and longer term decarbonisation goals, disincentivising such investment would add unwelcome additional challenge to an already highly-demanding target.

One compromise approach could be to shield "hard-to-relocate" renewables generators from the full locational signal, such as through continuing support via Contracts for Difference, or potentially a hedging mechanism. At the same time, other actors, such as batteries and other "relocatable" despatchable generators, and ideally also some demands (especially "relocatable" and / or "despatchable" energy consumers, such as industrial energy users), could be exposed to locational and real-time operational signals. Whether such a "partial locational pricing" system would justify the cost of such a scheme's introduction is a decision for others to make. Few dispute a case for reform of current arrangements, but some favour alternative less disruptive approaches, such as reform of TNUoS and balancing charging [264], [265].

The decision on REMA was announced in July 2025: the UK Government decided to retain 'national' pricing [266].

Option 3: revise the rules restricting battery ownership, or incentivise batteries to serve the system

Much of the literature in Chapter 2 discussed storage assets, under direction of a system or network operator, bringing considerable benefit to networks, and being of wider benefit than storage operating in "self-interested" mode. However, unbundling regulations restrict or prohibit such an approach. Revisiting and potentially relaxing such restrictions, if they can be shown to be of wider economic benefit, and do not interfere with the existing markets for service provision, could be considered.

Creating additional flexibility services, or procuring them in greater quantities, would incentivise participating storage assets to relieve such and other problems. With higher number of batteries on the system and offering frequency response services, for example, prices have fallen, which is good news for electricity consumers who ultimately pay for these services. However, if future system stability and operation, under rapid decarbonisation pathway, requires greater volumes of available batteries or other types of assets, or will do so in a few years, some means of creating market signals to ensure their presence may be needed. An important question to address is *"how many GW of batteries (or other flexible assets) does and will the system need?"*

Option 4. Build more network.

Much of the literature assumes that batteries and other storage assets can substitute for additional network capacity, while others found to the contrary, as has this work.

Some studies found storage and additional network capacity to be complementary to one another, each allowing greater value from each other. This held for studies ranging from transmission reinforcement (e.g. [95] in Chapter 2, Section 2.3.2), to introduction of real-time ratings on distribution feeders, which allowed greater capacity at times (e.g. [78] in Chapter 2, Section 2.2.1.3).

Additional transmission and distribution capacity is undoubtedly needed in places, though it is likely that storage assets can have a useful role in managing some constraints, pending reinforcement, if suitably incentivised to do so.

Overarching research question:

9.1.5. Will installing, deploying and enabling suitable types and capacities of "flexibility" enable "decarbonisation at lowest cost"?

Additional system flexibility will be essential to enable economic operation and operability of a "clean" electrical power system, as traditional flexibility providers – thermal fossil-fuelled generators – are used less often, and low-carbon flexible or schedulable generation capacity[90] is limited.

However, this thesis has found that **deployment of flexible assets**, in the GB unbundled system, **does not guarantee their use to aid system challenges**.

Examples have been found where batteries would indeed be likely to aid system operability. Batteries, discharging at times of high demands and low renewables outputs, for example,

[90] Current low-carbon schedulable or flexible generators include some large hydro plants (water levels permitting), and, by some definitions, some biomass plants, depending on provenance of fuel. Gas-CCS and / or "clean" hydrogen-fuelled power stations are expected to be part of the future generation mix. [227]

could reduce maximum system demands, displace polluting and at times expensive fossil fuel generation, and reduce the capacity, and thus capital costs of such plant. In the right places, such flexibility can reduce maximum network flows, with potential for such behaviour to save costs by reducing or delaying network reinforcement needs, results found in some of the literature, though other studies found to the contrary.

However, this thesis also found numerous counter-examples of such behaviour, i.e. examples when batteries would exacerbate network flows and thus increase or make more urgent needs for network reinforcement. These occurred in locations and at times where patterns of generation and demands differed from those of the aggregated system. This thesis has then considered excessive and perversely-incentivised flexibility capacity to be a *problem to be managed*.

Broadly similar behaviours is also expected from other types of price-sensitive flexible generators and flexible demand users, at least in locations where network conditions over a local, regional or home-nation scale differ from conditions system-wide, or over which signals are based.

Furthermore, this work found the *type* of flexibility a provider offers is important. Short-duration batteries can be highly-effective at managing in-day variations in demands and utilising renewable energy abundant for a few hours, as well as ancillary service provision, but cannot operate over the timescales of days, weeks and seasons, that are also needed. A variety of flexibility resources will be needed to address these different system challenges.

Some literature cited in this thesis found different kinds of flexibility were complementary to one another; some studies found that storage and network reinforcement actions were mutually beneficial. So, this work concludes that deployment and enabling of storage and other suitable types of "flexibility", in the right amounts, in the right places, and incentivised to act in "system supporting" manners, would indeed facilitate decarbonisation at lowest cost. However, appropriate capacities of network will be required to get best value out of all assets, and appropriate price signals or other interventions will be needed to incentivise or coordinate their behaviour. Improvements on both aspects are needed.

One could view a "best use case" of batteries and other flexible assets as their contribution to the system's generation mix, and / or provision of essential services, with a capability or reliably exceeding that of other asset types, and / or at a lower cost (financial and / or carbon) than that of the alternative providers which the batteries or other flexible assets would displace. Such provision would aid system transition at lowest cost. The ongoing "SSEP"[91] and "RESP"[92] planning underway by NESO [267], [268] appear to be appropriate approaches to defining these needs.

This work is entirely within a GB context, but these findings would be expected to apply in other decarbonising unbundled power systems, where independently-owned generators and other assets choose where to locate and when to operate, in the absence of suitable incentives, or mechanisms of coordination or control.

9.2. Novelty and contributions

This work builds on a substantial body of prior work, investigating the likely effect of storage on electricity systems and network congestion.

This work is novel in several aspects:

- No other identified work investigated the question "what is a battery likely to do when it is windy?" in a GB context. This work has investigated and found against the hypothesis – assumed by other researcher and the ESO in 2023 - that "*a rational battery, engaged in wholesale trades, will not export at times of high wind energy availability in Scotland, nor will it add to network congestion*" (Chapter 5).
- No other identified work has investigated the question of "how are battery actions likely to affect distribution network flows, in areas of significant distributed wind?" in a GB context. This work has investigated and found against the hypothesis: *"deployment of suitably-sized distribution-connected batteries, engaged in wholesale electricity trades, will not increase congestion on distribution networks servicing residential load demand and windfarms."* (Chapter 6). This work thus, unfortunately, supports the conservative approach DNOs use when awarding network connections, of assuming "worst case" battery behaviour that could add to maximum import and export flows, for batteries connecting in demand-only and wind-dominated areas.
- No other identified work has attempted to quantify the cost of curtailment of and to distribution-connected batteries, under a flexible connection scenario within GB,

[91] Strategic Spatial Energy Planning
[92] Regional Energy Strategic Planning

where a battery would connect in an area of high penetration of distributed wind, as is common in rural Scotland as well as some areas elsewhere in Britain (Chapter 7).

- No other identified academic work in a GB context has assumed or found that a grid-scale battery installation might actually cause a network reinforcement need, and then
  - compared projected costs of battery curtailment with those of traditional network reinforcement,
  - identified areas where each approach is likely to be lower cost (Chapter 8). Even allowing for uncertainties in costing used, the generic result: "there are circumstances in which battery curtailment costs would be lower than those of battery-triggered network reinforcement" is considered robust.
- Relatively few prior works use an agent-based modelling approach, as is used here (Section 4.2- 4.3); use of various types of optimisation is more usual. Agent-based modelling has the strength of deriving several plausible scenarios of battery actions, for each season and battery type. While a battery owner would surely wish to ask the question "what actions ***should be*** taken to maximise income?" the agent-based approach better addresses the question of interest to a system or network operator "what kinds of actions ***could be*** expected from batteries?"
- An approach to battery sizing, relative to spare network capacity (Chapter 7, Section 7.3 and 7.4), which allowed curtailment costs vs battery "oversize relative to network capacity" to be compared across different case study locations (Chapter 7, Section 7.4 and 7.5)
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9.3. Further work

This work could usefully be extended in a number of ways.

- Modelling in locations with high penetrations of solar, or potentially hydro resources, to understand if the findings are specific to wind, or would apply to other types of renewable generation.
- Modelling in locations with demands other than residential, such as various commercial or industrial loads, including electrifying / decarbonising industrial sites, to understand whether or not the findings of this work may apply to networks serving such demands

- Modelling in other geographical locations, such as the East England, where network constraints are expected following greater connected volumes of large offshore windfarms and international interconnectors.
- Use of other representations to depict and quantify possible correlations, for example between wind and price data, or battery activity and wind data. Multivariate "hit" tests [269], [270] may be particularly suitable. Extending the analysis with more prolonged datasets of past wholesale price data, or with synthesised future wholesale prices relating to a future decarbonising / decarbonised GB system.
- Modelling battery actions with a price dataset representing future system-wide pricing patterns expected as the system decarbonises, together with projected generation (locally, regionally and nationally) and projected changes in demand patterns. If gas generators are no longer price-setters at times, then wholesale prices would be likely to respond to outputs of renewable generators, including wind. This may much better incentivise them to respond to network needs. However, conditions of high solar / low wind, or high wind / low solar, for example, may have similar effects on prices, but cause very different network needs in different locations, as might differing weather conditions across GB affecting both solar and wind outputs.
- Modelling battery actions with a price dataset representing likely prices in the event of locational pricing being adopted.
- Developing the battery model
    - to give it more agility in changing trading parameters in response to changing patterns in price, or alternatively, to recalculate daily.
    - If considering longer duration storage, increase of the number of trading scenarios available around the "busy" scenario
    - As an alternative, consider a battery model which optimises actions according to wholesale price
    - For Chapter 7,
        - consider scenarios in which a battery owner has imperfect or no knowledge of network constraints, with which to inform its trading actions
        - consider non-firm battery connections under 'N' and 'N-1' conditions, introduce probabilistic modelling to better understand likely durations of contingencies.

    - To include battery degradation in modelling
    - To include further sensitivities for different degradation-avoiding actions that batteries may choose, or operational constraints that may be necessary
- Assessment of the business case for a battery storage asset:
    - Determine the income necessary to cover its costs
    - Develop a model which simulates battery behaviour across multiple revenue streams, and projects potential overall incomes
    - Determine in which circumstances such a battery may be financially viable
- Consider other sources of flexibility, such as flexible demands and hot water storage, and their likely availability and costs.
- Consider the potential for relocatable storage to manage temporary network constraints pending network reinforcement
- Considering what additional regulatory and / or market changes, and innovative business models for storage providers could incentivise storage assets to engage in activities which more closely align with system needs.

9.4. Recommendations to policy makers

This work is intended to inform DNOs, TOs, the ESO, the regulator Ofgem, and the UK Government, on some of the likely impacts of greater roll-out of batteries on the GB network, and its potential effects on our country's journey to decarbonise the electricity system and wider economy. This work may also be useful to some battery owners and their trade associations.

1. For the ESO: **Review the likely interactions of batteries and wind generation in Construction Planning Assumptions**
   This work found against some of the assumptions that NESO recently incorporated into its Construction Planning Assumptions, which the ESO uses to plan for the impacts of future connections to the grid. This work found to against the assumption "a battery does not typically export at times of peak generation" when considering wind generation in Scotland. Regarding the ESO's assumption "a battery does not typically import at times of peak demand", this work concurs, but a battery may import at times of regional *high demand*, such as the middle of the day, in locations with little or no connected solar generation. Details are tabulated in Chapter 9 Annex 1.

2. For the ESO: **Planning for network and system needs.**
    a. How much capacity of batteries are needed or desirable now, and in the future? Are there locations where batteries would be more or less beneficial? Is further action needed to enable greater battery deployment, and if relevant, where most needed?
    b. Are short-duration batteries an appropriate tool for delivering some of the desired flexibility, or are other types of asset, such as longer-duration storage needed?
    c. Are there lower-cost low-carbon alternatives, such as low-carbon flexible demands, available or potentially available, at the required volumes and in the required locations, to provide flexibility services, and what actions may enable such flexibility? If greater volumes of batteries are needed to deliver services, are additional service payments needed to incentivise batteries to be the most valuable contributors to grid operation as it decarbonises?
3. For DNOs, the ENA, TOs, ESO and Ofgem**: in areas where actions of short-duration batteries may exacerbate network congestion, consider making flexible connections a default offering**

    This suggestion would build on existing Tactical Guidance issued by the ENA, with Ofgem approval, for DNOs in late 2023, suggesting a "lower firmness of connection" for batteries than for other types of users, under outage conditions. Results in Chapters 7 and 8 were promising regarding the potential to oversize batteries, by several MW in excess of network capacity, and where curtailment would be needed, but reductions in projected revenues from wholesale trades were found to be small in some cases. This was especially the case for shorter duration batteries.
4. For the ESO, TOs, DNO/ DSOs, Ofgem, and the UK Government: **Investigate means of enabling storage / flexibility to manage temporary network constraints pending reinforcement**

    In many areas, batteries might be a useful way to manage a temporary network constraint pending reinforcement, potentially at Transmission[93] as well as Distribution

[93] The ESO was considering the use of batteries in its "Grid Booster" option [157] as an additional means to manage constraints over the constrained "B6" transmission boundary, which delimits the transmission network in Scotland from that further south (Picture of transmission boundaries in Chapter 5 Annex 1.)

level, provided the duration of constraint management is within the capability of the battery's discharge / charging time. Even where an immediate network reinforcement is a desired and is a lowest-cost solution, delays are common for reasons including consenting processes and potentially also constraints in resources, both human and supply chain. However, the building of a viable business case for a battery to provide such relief may be difficult if the need for constraint relief services is expected to be short-lived. Investigation into the practicalities of alternatives approaches is recommended. Such other approaches could include: relocatable battery solutions; other types of payments for batteries or other constraint management service providers; revisiting rules prohibiting network owners from owning and operating storage for specific purposes of network operation.

5. For the UK Government and Ofgem: **Take steps to make data more widely and easily available for researchers**
The country is endeavouring to adapt to demands of the Climate Emergency and goals to decarbonise the electricity system and wider economy at a pace that will be extremely challenging. The availability of relevant datasets is fundamental to any work to model future electricity and other energy needs and the way these needs might be met. Easier and fuller access to data could improve the relevance and quality of research on this transition, by academics and others , and enable them to do this work in a more time- and cost-effective manner. Access to wholesale electricity price platforms (day-ahead and intraday auctions) and costings of network reinforcements would be particularly valuable; better provision and clarity of metadata on distribution network Open Data platforms would also be helpful. Detailed recommendations, based on the experience of research for this thesis, are presented in Chapter 9 Annex 2.

9.5. Concluding remarks

This work set out to find answers and solve problems relevant to GB's electricity system and wider energy transition, regarding the assets and resources the system will need.

The results in Chapters 5 & 6 are not the ones I had set out to find. I had envisaged finding results which would strengthen the case for greater roll-out of storage, and arguments for the facilitation of such deployment. I had also expected to state with confidence that DNOs are being over-cautious in granting firm connections to batteries only where network capacity would accommodate their "worst case" actions, and to conclude other criteria for connection decisions were more appropriate. I would have preferred to have found such results.

Instead, my findings have been to the contrary. Rather than solving any problems, I have identified two additional and significant problems. The first is fairly obvious: *there is a limit to the problems that short-duration storage can solve: other types of asset are needed*. More serious is the second: *deployment of additional flexibility, in the wrong quantities, in the wrong places, and under the current signals – signals which at present are "wrong" at times in some locations - would be likely to **exacerbate** existing challenges of network congestion and insufficient network capacity*. This finding – though unwelcome – is important. It illustrates the complexity of overseeing a "market-led" transformation of generation, with emerging technologies, in an unbundled and increasingly decentralised system, and one where there is significant divergence in conditions across times and across places within the GB system.

Thus, the question: "s*o, what should be done?*", is rather messier.

Reverting to a centrally-controlled system could potentially address this matter, though such an approach would be in contradiction to over three decades of GB operational and legal frameworks, and would remove advantages that have come with allowing independent generators and innovators to participate in competition with legacy providers in our mix. Finer tuning of rules or price signals, perhaps limiting connected or operational capacity of certain types of assets in certain locations may be necessary, and indeed such recommendations may emerge from some the system planning processes that the newly-created National Energy System Operator is undertaking.

So much for solving problems.

Regarding finding answers, yes, this work has found answers, but has identified far more questions. Besides the "further work" identified above in Section 9.3, there are higher level questions:

- What kinds of storage, and other flexibility providers – operating over different timescales – does the GB system want, and does it need?
- Where, and up to what capacity?
- How much storage capacity is *too much*?
- What activities do we want storage assets to do, and what should we allow them to do?

- What means should be used to encourage, discourage and potentially limit their activities?
- What is the balance of benefit for both the system and the asset owners?

Perhaps a thesis is never finished, but highlights further gaps in knowledge and needs for others to explore.

Thesis Annexes

Annexes to Chapter 3
Battery activities in GB: what are the options?

Contents

Figures for Chapter 3 Annexes

Tables for Chapter 3 Annexes

Chapter 3 Annex 1
Batteries in GB: deployment and potential deployment

1.1 Digest of UK Energy Statistics. Storage: PHS & Battery - deployment to date.

Table 66 Power capacity of energy storage facilities, MW. DUKES 2024 table 5.16C.[36] All figures in MW.

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023
PHS	2,744	2,744	2,744	2,744	2,744	2,744	2,744	2,744	2,744
Battery	0	0	108	487	676	914	1,280	1,933	3,465

The above figures exclude "behind the meter" batteries at domestic or commercial facilities. These figures include all of UK, i.e. facilities in Northern Ireland as well as GB. DUKES does not list a breakdown of battery storage capacity by UK home nation (i.e. battery storage is not included in its lists of "major power producers", for which geographical information is available).

1.2 Renewable Energy Planning Database (REPD)

The REPD [108] contains information about all "renewable" electricity projects in the UK which are known to Planning authorities, i.e. for which a Planning application has been submitted. The term "renewable" extends to include energy storage, both stand-alone and co-located with renewable or fossil-powered generators. The register includes all projects sized up to 1 MW electrical capacity up until 2021, and since then, also for projects sized up to 150kW. The figures below are for GB only i.e. they exclude Northern Irish entries.

Table 67 Aggregate capacity of stand-alone battery storage projects in GB, by development status, as listed on UK Government's REPD , as of October 2024 [108].

Development status	Total Capacity, MW	Number of entries	Percentage of entries with no or 'zero' entered project MW capacity
Operational	2,080	66	6%
Under construction	3,837	64	9%
Planning permission granted	24,958	403	18%
Planning decision awaited	30,083	360	13%
Planning refused	2,675	48	19%
Project withdrawn, abandoned or lapsed	2,633	118	10%
Decommissioned	7	8	0%

Unfortunately this register has no information about whether a project would connect to a Transmission or Distribution electricity network.

1.3 NESO: Transmission Entry Capacity (TEC) Register

NESO (formerly called National Grid, and National Grid ESO) publishes a "Transmission Entry Capacity (TEC) register [271], which lists all generator assets known to the ESO. It is the primary source of information for all transmission-connected assets (listed as "direct connection"). The TEC register also has information about some distribution-connected assets (listed as "embedded"), those known to the ESO (e.g. assets which participate in the Balancing Mechanism), though this register is a very incomplete source of information for distribution-connected assets.

Table 68 NESO's TEC Register 15-11-2024 [43]. Aggregate capacity of "Energy Storage System" projects, by development status. Projects listed as energy storage co-located with generation or demand are excluded.

Status	"Direct Connection" MW	"Embedded" MW	Total MW
Built	706	658	1,365
Under construction	230	230	460
Consented	4,594	724	5,318
Awaiting consents	6,452	139	6,591
Scoping	119,687	11,685	131,372

1.4 DNO Embedded Capacity Registers (ECRs)

The totals use the Embedded Capacity Register (ECR) from all six DNO owners, covering the 14 DNO regions within GB [37]–[42]. In all cases, the Register Part 1, for projects sized at or above 1 MW capacity, is used. All registers were accessed on 20/11/2024.

Table 69 DNO ECRs [37]–[42] : total numbers of entries across all licence areas. All entries for assets of 1 MW or greater capacity

DNO	Licence areas	Number of Licence Areas	Number of entries
SSEN	Northern Scotland; South England	2	1516
SPEN	Southern Scotland; Manweb NW England (Mersey & Cheshire) & North Wales	2	1005
NPG	North East England ; Yorkshire	2	983
ENWL	NW England (Cumbria, Lancs.)	1	552
NGED	English West Midlands; English East Midlands; SW England; South Wales	4	2266
UKPN	Eastern England; South Eastern England; London	3	1238

Table 70 DNO ECRs [37]–[42]: total numbers of entries of all generators, and of storage and batteries listed as primary energy source. All entries for assets of 1 MW or greater capacity

Criteria	Number of entries
All	7560
Not storage	6111
Storage as “Energy Source 1” – all types	1450
Storage stated as (or presumed to be) batteries. [94] Excludes storage described as mechanical, hydro, flywheel or thermal.	1420
Batteries - connected[95]	132
Batteries - accepted to connect[96]	1288

[94] Majority of entries described as “batteries”, “electrochemical” or “electrical” storage, or described as “storage – other” but includes “BESS” or “battery” in site name. This total includes 20 MW of assets described as “storage – other” with no further information.

[95] All entries with “connection status” column holding “Y”, or “connection status” column blank, but with a date of connection in the past.

[96] All entries with “connection status” column not containing “Y”, excluding entries with a connection date in the past.

Table 71 Total capacity of battery projects (=>1MW) across all DNO regions, by connection status. From DNO ECRs [37]–[42]

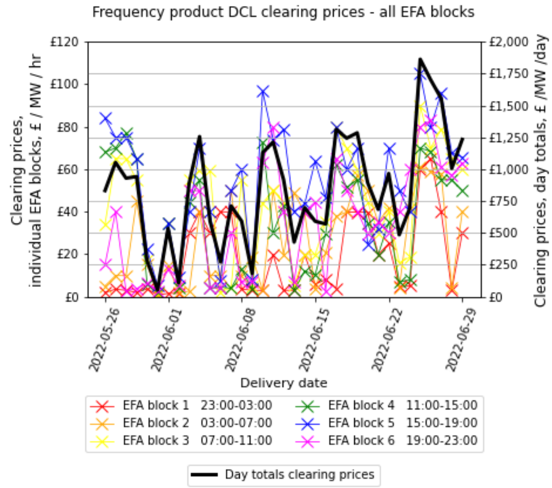
Column / criterion	Projects of "Connected" status			Projects of "Accepted to connect" status			Projects of all connection statuses		
	Total MW or MVA	Number of entries blank or zero	Fraction of entries blank, out of 132 entries	Total MW or MVA	Number of entries blank or zero	Fraction of entries blank, out of 1288 entries	Total MW or MVA	Number of entries blank or zero	Fraction of entries blank, out of 1420 entries
Energy Source & Energy Conversion Technology 1 – Registered Capacity (MW)	3,050	10	8%	84,348	0	0%	84,348	10	1%
Energy Source & Energy Conversion Technology 2 – Registered Capacity (MW)	3	127	96%	938	1,254	97%	938	1,381	97%
Energy Source & Energy Conversion Technology 3 – Registered Capacity (MW)	0	132	100%	45	1,287	100%	45	1,419	100%
Already connected registered capacity (MW)	3,234	5	4%	3,234	1,288	100%	3,234	1,293	91%
Maximum Export capacity (MW)	3,279	2	2%	3,279	1,288	100%	3,279	1,290	91%
Maximum Export capacity (MVA)	2,895	18	14%	2,895	1,288	100%	2,895	1,306	92%
Maximum Import capacity (MW)	2,371	35	27%	2,371	1,288	100%	2,371	1,323	93%
Maximum Import capacity (MVA)	2,028	49	37%	2,028	1,288	100%	2,028	1,337	94%
Accepted to connect registered capacity (MW)	64	128	97%	82,042	0	0%	82,042	128	9%
Change to Maximum Export capacity (MW)	109	127	96%	75,556	129	10%	75,556	256	18%
Change to Maximum Export capacity (MVA)	545	108	82%	79,101	134	10%	79,101	242	17%
Change to Maximum Import capacity (MW)	107	128	96%	57,864	350	27%	57,864	478	34%
Change to Maximum Import capacity (MVA)	112	128	82%	62,788	354	27%	62,788	482	34%

Chapter 3 Annex 2

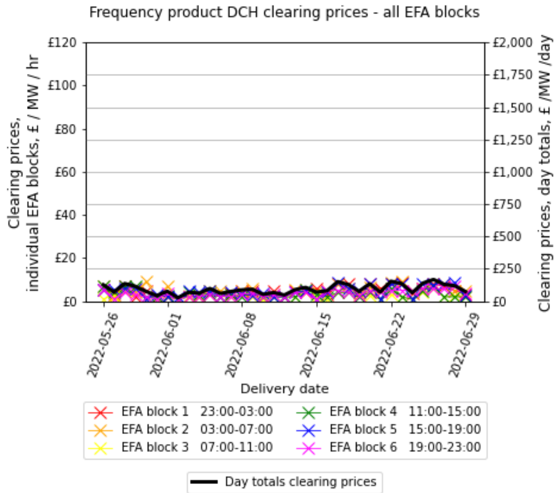
Frequency response products DC, DM and DR. Timeseries clearing prices for each product, during summer, autumn and winter case study seasons.

Figures on the following pages

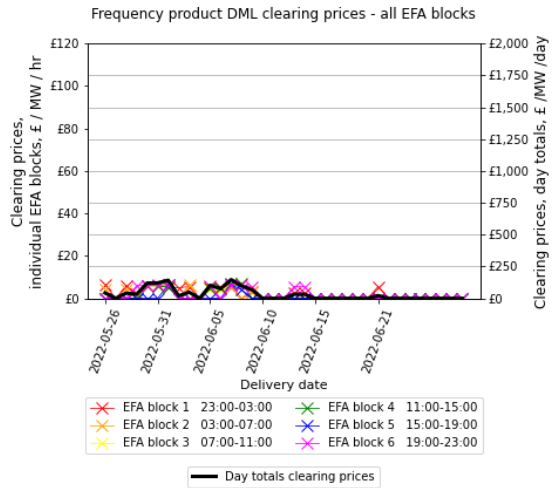
Summer



(a) DCL (summer 2022 case study period)



(b) DCH (summer 2022 case study period)



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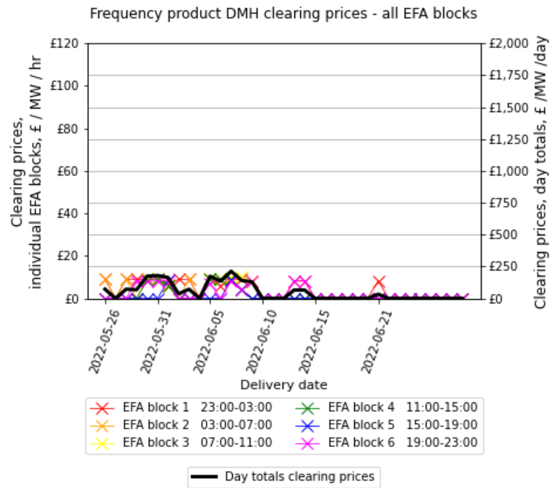
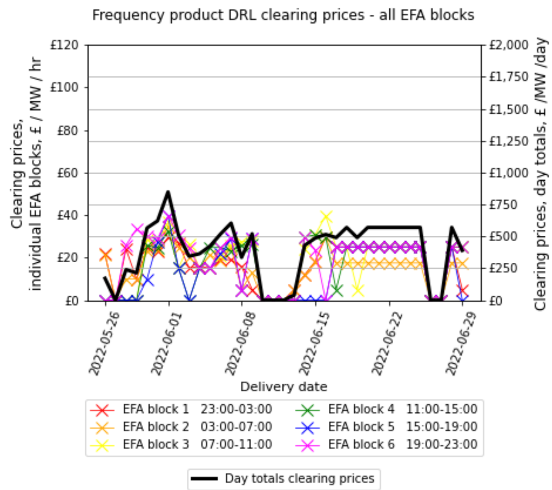
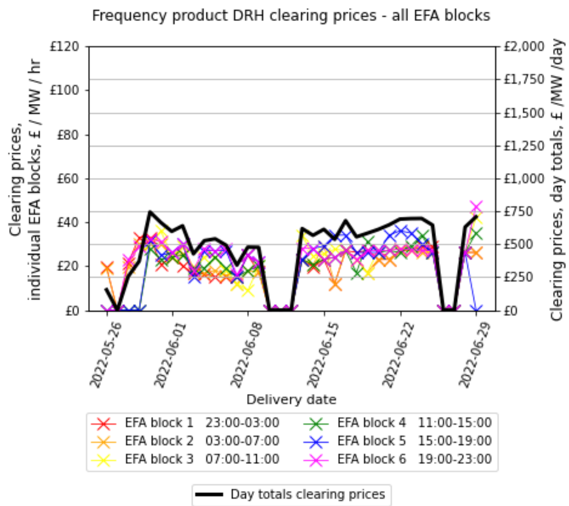


(d) DMH (summer 2022 case study period)



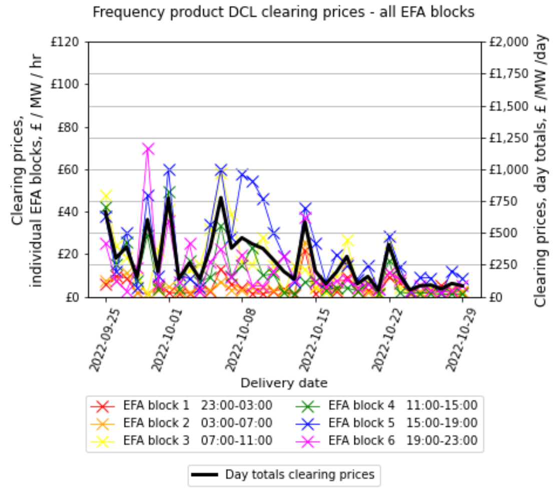
(e) DRL (summer 2022 case study period)



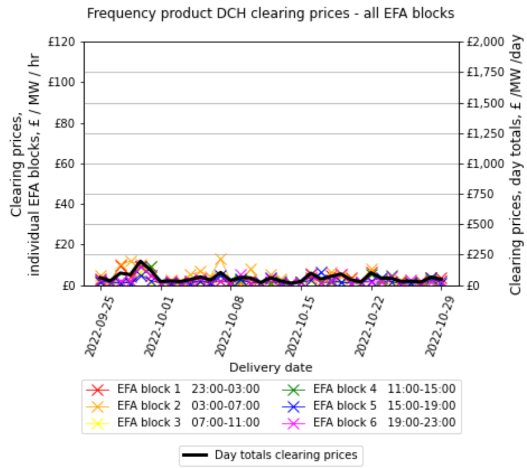
(f) DRH (summer 2022 case study period)

Figure 123 Summer case study. Timeseries of clearing prices of frequency response services DC, DM and DR, split by EFA block Data from [133]

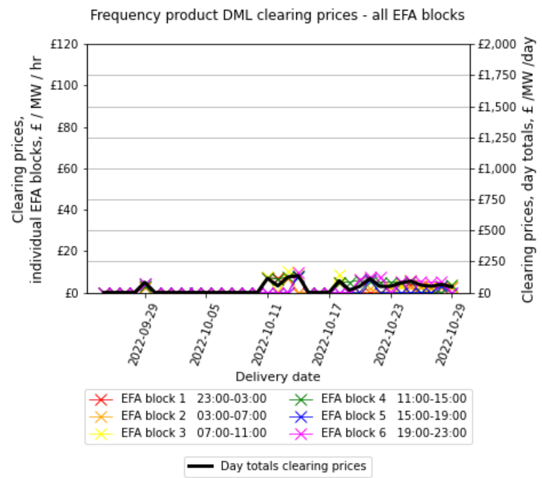
Autumn



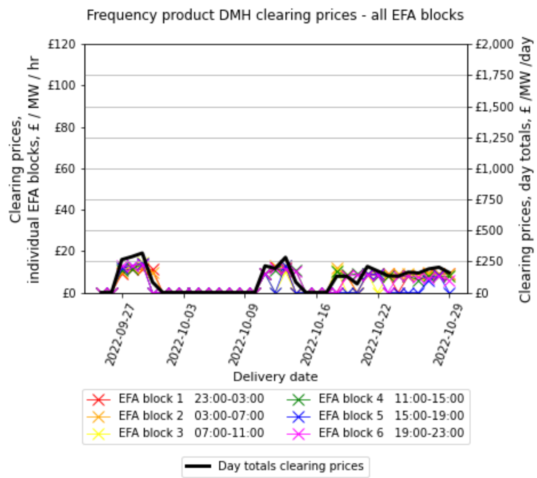
(a) DCL (autumn 2022 case study period)



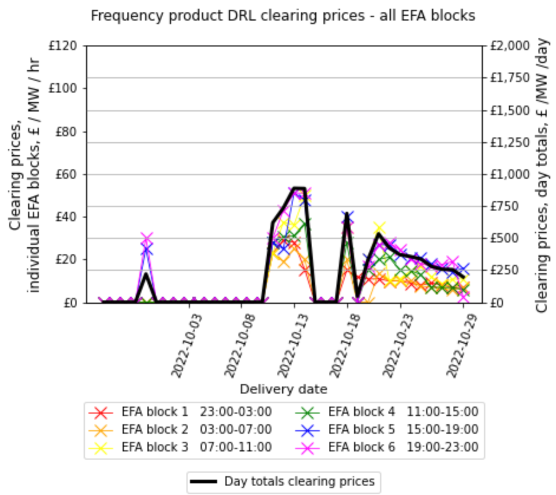
(b) DCH (autumn 2022 case study period)



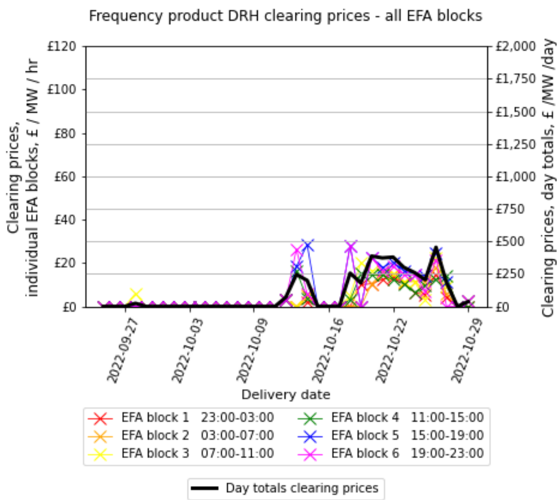
(c) DML (autumn 2022 case study period)



(d) DMH (autumn 2022 case study period)



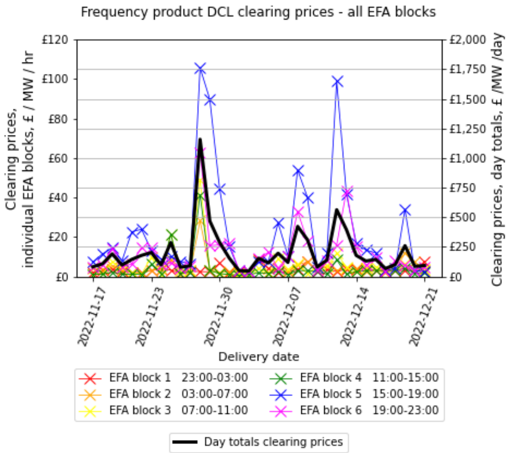
(e) DRL (autumn 2022 case study period)



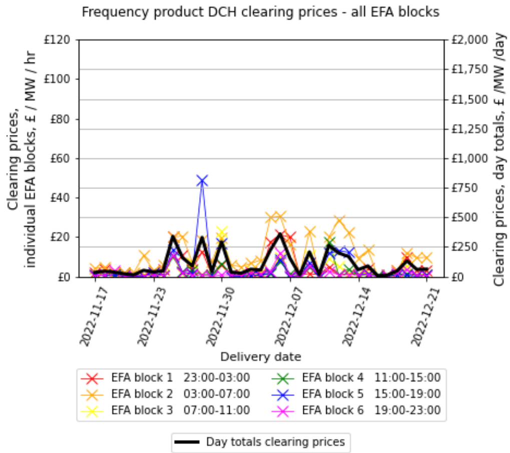
(f) DRH (autumn 2022 case study period)

Figure 124 Autumn case study. Timeseries of clearing prices of frequency response services DC, DM and DR, split by EFA block Data from [133]

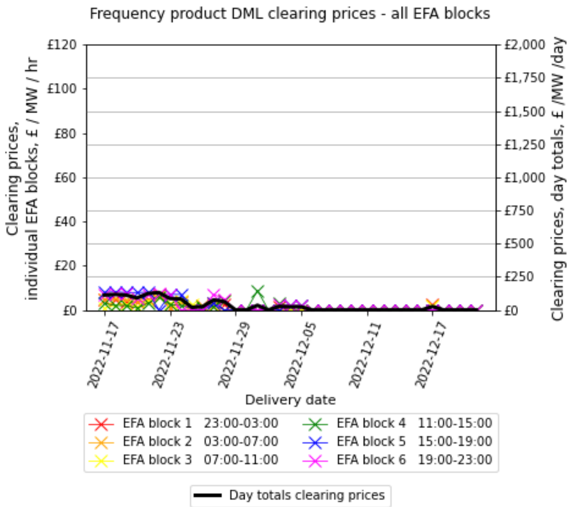
Winter



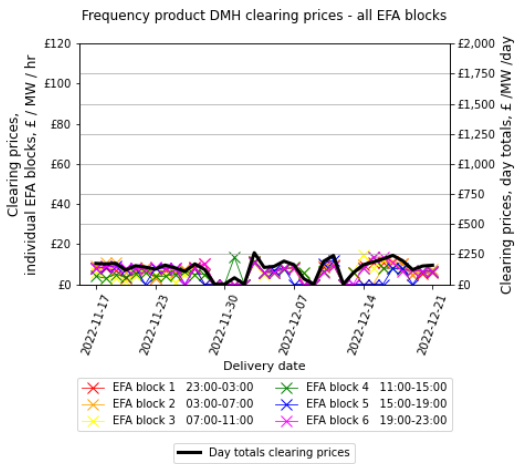
(a) DCL (winter 2022 case study period)



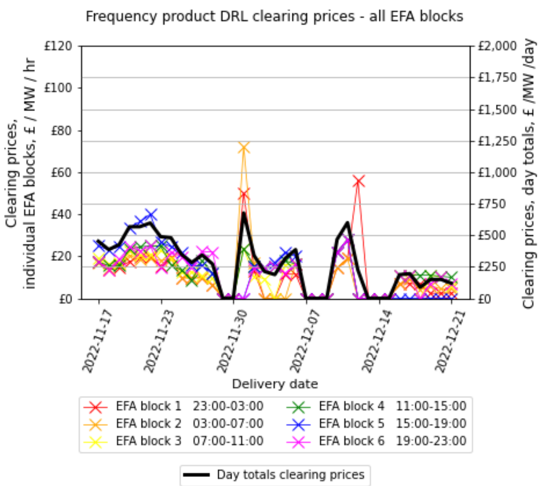
(b) DCH (winter 2022 case study period)



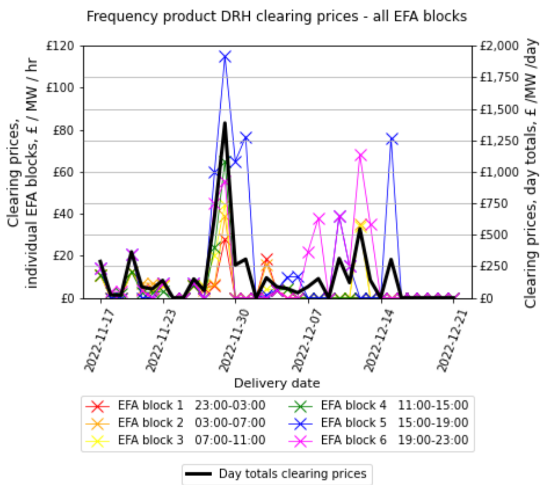
(c) DML (winter 2022 case study period)



(d) DMH (winter 2022 case study period)



(e) DRL (winter 2022 case study period)



(f) DRH (winter 2022 case study period)

Figure 125 Winter case study. Timeseries of clearing prices of frequency response services DC, DM and DR, split by EFA block. Data from [133]

Chapter 3 Annex 3

Summary of activity (frequency response, wholesale trades and BM actions) of real batteries on GB network, 2022.

Table 72 Real GB batteries engaging in frequency response (DC, DM and / or DR) [133] and / or wholesale and / or BM trades [272] during 2022. Dates of first activity.

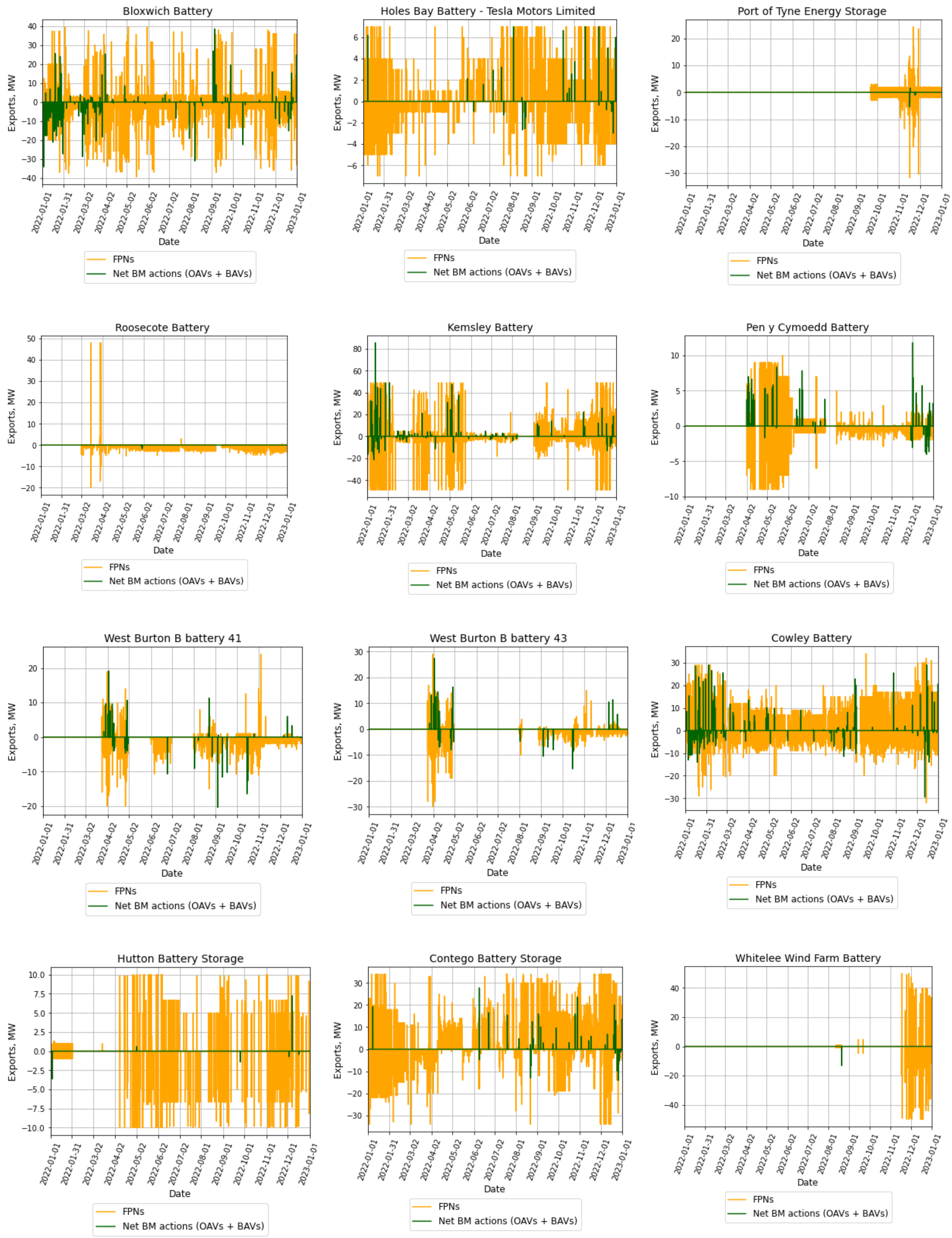
Battery owner	Battery name	Battery BM identifier	Date of first DC-DM-DR FR delivery	Wholesale trades and BM actions			Days between first trade / BM action & first FR dates
				Wholesale trades	BM actions		
				Date of first FPN	Date of first BAV	Date of first OAV	
Statkraft Markets GMBH	Arbroath	ARBRB-1	26/11/2022	25/11/2022	17/12/2022	05/12/2022	1
Arenko Cleantech Ltd	Bloxwich	ARNK-1	01/01/2022	01/01/2022	03/01/2022	05/01/2022	0
	Hutton	ARNK-2	01/01/2022	01/01/2022	03/01/2022	02/05/2022	0
Tesla Motors Ltd	Holes Bay	BHOLB-1	01/01/2022	01/01/2022	09/06/2022	07/01/2022	0
SMS Energy Services Ltd	Burwell	BURWB-1	26/02/2022	26/01/2022	27/01/2022	02/02/2022	31
Tesla Motors Ltd	Contego	CONTB-1	01/01/2022	01/01/2022	09/06/2022	07/01/2022	0
Habitat Energy Ltd	Cowley	COWB-1	01/01/2022	01/01/2022	01/01/2022	02/01/2022	0
Tesla Motors Ltd	Hawkers Hill	HAWKB-1	25/10/2022	01/10/2022	None	07/12/2022	24
EDF Energy Customers Ltd	Kemsley	KEMB-1	01/01/2022	01/01/2022	01/01/2022	05/01/2022	0
Tesla Motors Ltd	Pillswood 1	PILLB-1	30/12/2022	07/12/2022	None	06/12/2022	23
EDF Energy Customers Ltd	Capenhurst 1[97]	PINFB-1	17/12/2022	27/05/2022	02/12/2022	02/12/2022	204
	Capenhurst 2	PINFB-2	17/12/2022	27/05/2022	02/12/2022	02/12/2022	204
	Capenhurst 3	PINFB-3	17/12/2022	27/05/2022	02/12/2022	02/12/2022	204
	Capenhurst 4	PINFB-4	17/12/2022	27/05/2022	02/12/2022	02/12/2022	204
Arenko Cleantech Ltd	Pen y Cymoedd	PNYCB-1	12/08/2022	01/04/2022	28/04/2022	01/04/2022	133
	Port of Tyne	POTES-1	05/08/2022	01/11/2022	16/11/2022	17/11/2022	-88
Centrica Business Solutions UK	Roosecote	ROOSB-1	01/03/2022	01/03/2022	29/05/2022	29/05/2022	0
EDF Energy Customers Ltd	West Burton B Batt 41	WBURB-41	09/04/2022	24/03/2022	08/04/2022	27/03/2022	16
	West Burton B Batt 43	WBURB-43	09/04/2022	24/03/2022	08/04/2022	27/03/2022	16
	Nursling battery	T_NURSB-1	2023	None	None	None	> 471
	Whitelee Windfarm Batt[98]	WHLWB-1	None	12/08/2022	20/08/2022	20/08/2022	>141
	Hunningley Stairfoot	BARNB-1	None	22/12/2022	None	None	>9
	Pillswood 2	PILLB-2	None	24/12/2022	None	None	>7
	Skelmersdale	SKELB-1	None	16/12/2022	None	None	>15

[97] Capenhurst batteries 1-4 had initial wholesale trades briefly in May 2022, but did not commence regular wholesale trades till December 2022.
[98] Whitelee windfarm battery had initial activity in August and September 2022, but did not commence regular activity until November 2022.

Chapter 3 Annex 4

GB battery FPNs and BM trades, 2022

The graphs below are timeseries plots of FPNs and net balancing actions (sum of OAVs and BAVs) for every SP during 2022, for all batteries listed by Elexon which had activity during that year.



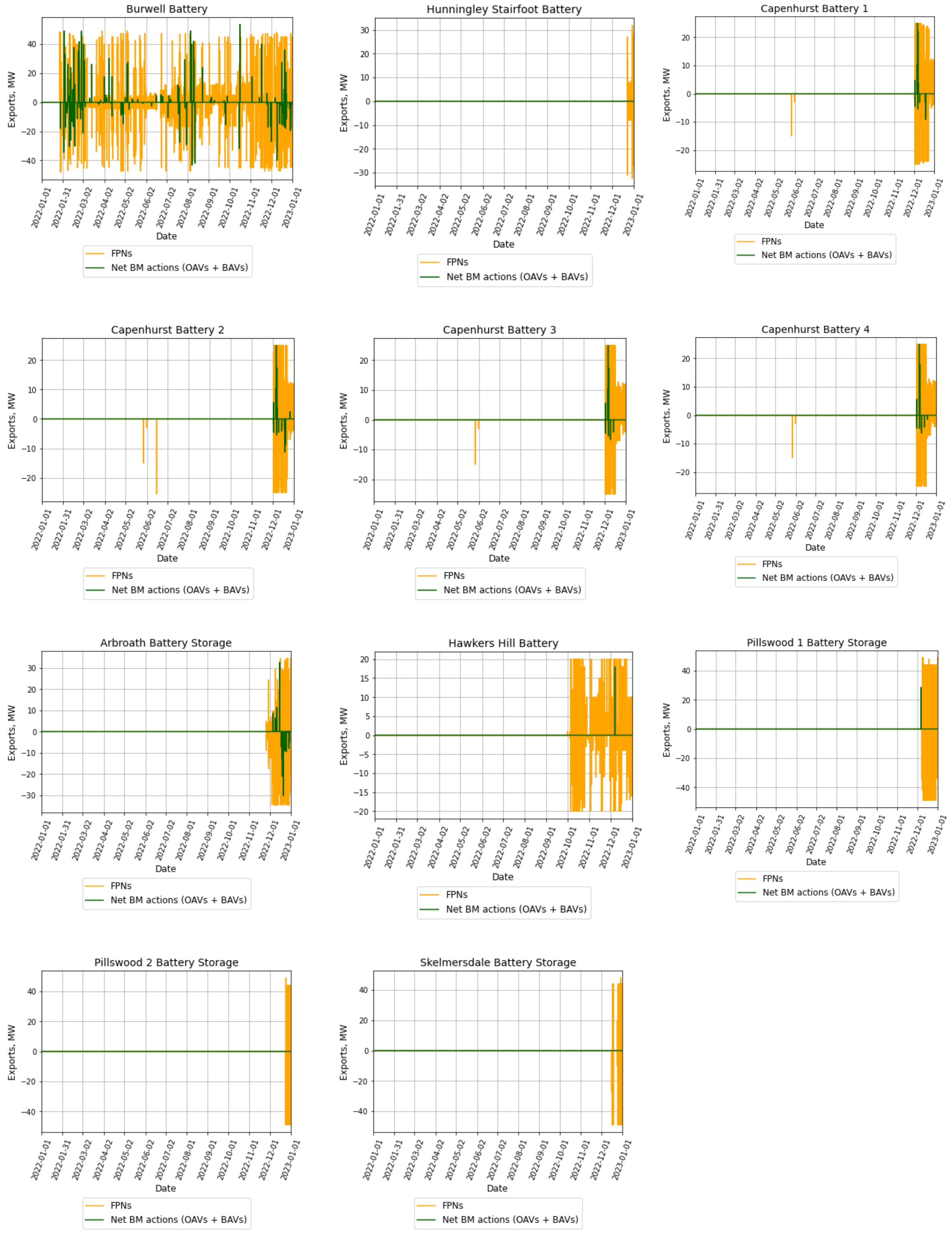


Figure 126 Timeseries charts of GB real battery FPNs and BM trades during 2022 [272]

Chapter 3 Annex 5

Battery activities during the summer, autumn and winter case studies

Table 73 summarises the activities that real GB-connected batteries engaged in during the three case study periods.

The columns with information about BM trades list the proportion of energy exported and imported, as a percentage of the total FPN exports or imports, respectively, over the same period. Out of the three case study seasons, BM trades only amounted to significant volume (defined as > 80% of the compared to FPN volumes ("significant" here is defined BM volumes > 80% of FPN volumes), for three batteries (Pen y Cymoedd, West Burton B no 41 & 43, numbered 6-8 on the table), and for these, only during the winter case study period, and only when exporting.

Out of the other batteries and case study seasons, BM trades were far smaller, with two instances of BM trades comprising 10-25% of FPN volumes (summer case study, exporting only). In all other cases BM volumes were under 10% of FPN volumes.

Table 73 Individual battery activities (wholesale trades, BM trades [272], and provision of DC/DM/DR frequency response services [133], for each case study season, 2022.

	Battery BMU	Summer				Autumn				Winter			
		FPNs	BM trades: BM MWh / FPN MWh		FR: DCDM DR	FPNs	BM trades: BM MWh / FPN MWh		FR: DCDM DR	FPNs	BM trades: BM MWh / FPN MWh		FR: DC DM DR
			Exports	Imports			Exports	Imports			Exports	Imports	
1	E_ARNKB-1	Yes	1%	0.1%	Yes	Yes	3%	3%	Yes	Yes	2%	3%	Yes
2	E_BHOLB-1	Yes	1%	4%	Yes	Yes	5%	0	Yes	Yes	6%	0.3%	Yes
3	E_POTES-1	No	No	No	No	Yes	No	No	No	Yes	0.2%	0.2%	Yes
4	E_ROOSB_1	Yes	0	0.4%	Yes	Yes	No	0	Yes	Yes	No	No	Yes
5	T_KEMB-1	Yes	22%	0.3%	Yes	Yes	1%	<0.1%	Yes	Yes	3%	1%	Yes
6	T_PNYCB-1	Yes	10%	0	No	Yes	No	0	Yes	Yes	88%	8%	Yes
7	T_WBURB-41	Yes	0	2%	Yes	Yes	1%	5%	Yes	Yes	310%	0	Yes
8	T_WBURB-43	No	No	No	No	Yes	0	6%	Yes	Yes	130%	0	Yes
9	T_COWB-1	Yes	1%	0.5%	Yes	Yes	2%	0	Yes	Yes	7%	5%	Yes
10	E_ARNKB-2	Yes	No	No	Yes	Yes	0	2%	Yes	Yes	5%	0.4%	Yes
11	E_CONTB-1	Yes	3%	3%	Yes	Yes	3%	0	Yes	Yes	2%	0.1%	Yes
12	T_WHLWB-1	No	No	No	No	No	No	No	No	Yes	No	No	No
13	E_BURWB-1	Yes	2%	0.3%	Yes	Yes	2%	3%	Yes	Yes	4%	10%	Yes
14	E_BARNB-1	No	No	No	No	No	No	No	No	No	No	No	No
15	T_PINFB-1	(yes)	No	No	No	No	No	No	No	Yes	8%	5%	
16	T_PINFB-2	(yes)	No	No	No	No	No	No	No	Yes	8%	7%	Yes
17	T_PINFB-3	(yes)	No	No	No	No	No	No	No	Yes	8%	2%	Yes
18	T_PINFB-4	(yes)	No	No	No	No	No	No	No	Yes	6%	2%	Yes
19	E_ARBRB-1	No	No	No	No	No	No	No	No	Yes	9%	7%	Yes
20	E_HAWKB-1	No	No	No	No	Yes	No	No	Yes	Yes	1%	0	Yes
21	E_PILLB-1	No	No	No	No	No	No	No	No	Yes	1%	0	No
22	E_PILLB-2	No	No	No	No	No	No	No	No	No	No	No	No
23	E_SKELB-1	No	No	No	No	No	No	No	No	Yes	No	No	No

Chapter 3 Annex 6
Capacity Market definitions

The following definitions are expressed in [159]:

Capacity Market Stress Event

For the purposes of this guide a Capacity Market Stress Event is a System Stress Event that has occurred at least four hours after a Capacity Market Notice has been issued and post-event analysis by National Grid ESO has confirmed that a System Stress Event has occurred.

System Stress Event

"A Settlement Period in which a System Operator Instigated *Demand Control Event* occurs where such event lasts at least 15 continuous minutes (whether the event falls within one Settlement Period or across more than one consecutive Settlement Periods, and where the event falls across multiple consecutive Settlement Periods, each of those Settlement Periods will be a "System Stress Event").

Demand Control Event

The Electricity System Operator (ESO) issues a Demand Reduction; and/or The SO issues an Emergency Manual Disconnection Instruction to one or more Distribution Network Operator (DNO); and/or An Automatic Low Frequency Demand Disconnection takes place.

Exceptions include events where such actions are caused by one or more fault in the Transmission Network or a Distribution Networks, or if volumes of energy reduction in Bid Offer Acceptances exceed those of the Demand Reduction Instruction, Emergency Manual Disconnection Instruction issued or the Automatic Low Frequency Demand Disconnection that took place.

Capacity Market Notice

Warnings are issued when National Grid ESO believes the expected available generation is within 500MW of expected demand.

Chapter 3 Annex 7

Capacity auction results

Capacity Market auction results. Auctions for service delivery during years 2022/2023 and 2023/24

Table 74 Capacity market auction results. Auction results for delivery during 2022/23 [160]–[163]

Auction	2019 T-3 2022/23				2021 T-1 2022/23			
Auction held	Feb 2020				Feb 2022			
Delivery year	2022/23				2022/23			
Storage duration	De-rating factor	Auction clearing price, £/kW/yr	Revenue, £/MW/yr	**Revenue, £/MW /day**	De-rating factor	Auction clearing price, £/kW/yr	Revenue, £/MW/yr	**Revenue, £/MW /day**
Storage – 1 hr	21.36%	£6.44	£1,376	**£3.77**	25.87%	£75	£19,403	**£53.16**
Storage – 2 hr	42.53%	£6.44	£2,739	**£7.50**	50.63%	£75	£37,973	**£104.03**
Storage – 4 hr	67.04%	£6.44	£4,317	**£11.83**	74.84%	£75	£56,130	**£153.78**

Table 75 Capacity market auction results. Auction results for delivery during 2023/24 [160], [161], [164], [165]

Auction	2019 T-4 2023/4				2022 T-1 2023/4			
Auction held	Mar-20				Feb-23			
Delivery year	2023/4				2023/4			
Storage duration	De-rating factor	Auction clearing price, £/kW/yr	Revenue, £/MW/yr	**Revenue, £/MW /day**	De-rating factor	Auction clearing price, £/kW/yr	Revenue, £/MW/yr	**Revenue, £/MW /day**
Storage – 1 hr	20.43%	£15.97	£3,263	**£8.94**	18.60%	£60.00	£11,160	**£30.58**
Storage – 2 hr	41.04%	£15.97	£6,554	**£17.96**	37.02%	£60.00	£22,212	**£60.85**
Storage – 4 hr	65.93%	£15.97	£10,529	**£28.85**	62.32%	£60.00	£37,392	**£102.44**

Capacity Market auction results. Auctions held during years 2022/2023 and 2023/24

Table 76 Capacity market auction results. T1 auctions held during 2022/23 and 2023/24 [161], [163], [165]

Auction	2021 T-1 2022/23				2022 T-1 2023/4			
Auction held	Feb 2022				Feb 2023			
Delivery year	2022/23				2023/4			
Storage duration	De-rating factor	Auction clearing price, £/kW/yr	Revenue, £/MW/yr	**Revenue, £/MW /day**	De-rating factor	Auction clearing price, £/kW/yr	Revenue, £/MW/yr	**Revenue, £/MW /day**
Storage – 1 hr	25.87%	£75	£19,403	**£53.16**	18.60%	£60.00	£11,160	**£30.58**
Storage – 2 hr	50.63%	£75	£37,973	**£104.03**	37.02%	£60.00	£22,212	**£60.85**
Storage – 4 hr	74.84%	£75	£56,130	**£153.78**	62.32%	£60.00	£37,392	**£102.44**

Table 77 Capacity market auction results. T4 auctions held during 2022/23 and 2023/24 [161], [166], [273]

Auction	2021 T-4 2025/26				2022 T-4 2026/7			
Auction held	Mar-22				Mar-23			
Delivery year	2025/ 26				2026/7			
Storage duration	De-rating factor	Auction clearing price, £/kW/yr	Revenue, £/MW/yr	**Revenue, £/MW /day**	De-rating factor	Auction clearing price, £/kW/yr	Revenue, £/MW/yr	**Revenue, £/MW /day**
Storage – 1 hr	9.98%	£30.59	£3,053	**£8.36**	11.81%	£63.00	£7,440	**£20.38**
Storage – 2 hr	39.73%	£30.59	£12,153	**£33.30**	23.63%	£63.00	£14,887	**£40.79**
Storage – 4 hr	64.86%	£30.59	£19,841	**£54.36**	45.86%	£63.00	£28,892	**£79.16**

Chapter 3 Annex 8

DSO Flexibility services: Auction results for SP Energy Networks

Table 78 SPEN DSO flexibility services tenders 2019-2022 [184]

Tenders	Spring 2019	Autumn 2019	Autumn 2020	Spring 2021	Autumn 2021
Delivery years	2019/20	2020/21, 2021/22, 2022/23	2023/24 to 2027/28	2023/24 to 2027/28	2022/23, 2023/24
No of sites	3	10	1138	1554	97
MWs tendered	116	250	960	1420	110.9
MWs awarded	0	53.3	139.6	555	0

Table 79 Successful battery bids in SPEN areas at DSO Flexibility auctions 2019-2021 [185]

DNO Service	**Location**	**Tender**	**Delivery dates**	**MW**	**Service window**	**Run & re-sponse time**	**Avail-ability fee, £/MW/h**	**Est. daily avail-ability payment, £/MW/ day**	**Utilis-ation price, £/ MWh**
Dynamic	SPM, Connah's Quay	Autumn 2019	1/11/21-1/3/22	4.7	16:00-19:30 weekdays	3 hrs / 15 mins	£5	**£16.50 weekdays only**	£400
Secure	SPD, Kaimes	Spring 2021	1/10/24-1/4/25	0.2	16:30-19:30	1 hr / 15 mins	£70	**£210**	£28
Secure	SPD, Kaimes	Spring 2021	1/4/25-1/4/26	0.2	15:30-21:00	1 hr / 15 mins	£29	**£159.50**	£28
Secure	SPD, Kaimes	Spring 2021	1/10/26-1/1/27	0.2	16:30-19:00	1 hr / 15 mins	£250	**£625**	£300
Secure	SPD, Kaimes	Spring 2021	1/10/27-1/4/28	0.2	16:00-19:30	1 hr / 15 mins	£250	**£625**	£300
Secure	SPM, Carrington	Spring 2021	1/10/27-1/1/28	0.081	18:00-19:00 weekdays	1 hr / 15 mins	£270	**£270 weekdays only**	£330

Table 80 Successful DSO Flexibility Auctions bids in SPEN areas, for delivery during 2022/23 [185]. All providers were fossil gas.

DNO Service	**Location**	**Tender**	**Delivery dates**	**MW**	**Service window**	**Run & re-sponse time**	**Avail-ability fee, £/MW/h**	**Est. daily avail-ability payment, £/MW/ day**	**Utilis-ation price, £/ MWh**
Restore	SPM, Connah's Quay	Autumn 2019	1/3/22-1/11/22	7.5	07:00-22:30 weekdays	3 hrs / 15 mins	£0	**£0**	£1,000
Dynamic	SPM, Connah's Quay	Autumn 2019	1/11-22-1/3-23	5.2	09:30-13:30 weekdays	3 hrs / 15 mins	£5.00	**£20.00**	£400
Dynamic	SPM, Connah's Quay	Autumn 2019	1/11-22-1/3-23	5.2	16:00-19:30 weekdays	3 hrs / 15 mins	£5.00	**£17.50**	£400
Dynamic	*SPM, Fiddlers Ferry*	*Autumn 2019*	*1/3/22-1/11/22*	*4.0*	*17:00-18:00 weekdays*	*10 hrs / 15 mins*	*£29.40*	***£294***	*£100*
Dynamic	*SPM, Fiddlers Ferry*	*Autumn 2019*	*1/3/22-1/11/22*	*3.4*	*17:00-18:00 weekdays*	*10 hrs / 15 mins*	*£39.40*	***£294***	*£100*
Dynamic	*SPM, Fiddlers Ferry*	*Autumn 2019*	*1/3/22-1/11/22*	*4.0*	*17:00-18:00 weekdays*	*10 hrs / 15 mins*	*£19.40*	***£194***	*£100*

Table 81 DSO Flexibility Auctions bids in SPEN areas, offered by stored energy providers, for delivery during 2022/23 [185]. All bids were unsuccessful.

DNO service	Licence area	Location	Tender	MW	Run / response time	Contract start	Contract end	Service window start time	Service window end time	Offered availability fee, £/MW/h	Offered utilis'n fee, £/MWh	Notes
Dynamic	SPD	Berwick	Autumn 2019	3.9	*10 hrs / 15 mins*	01/10/2022	01/03/2023	00:00	23:30	10.0	200.0	
Dynamic	SPD	Leven	Autumn 2019	0.7	*10 hrs / 15 mins*	01/11/2022	01/02/2023	16:00	18:30	75.0	600.0	
Dynamic	SPD	Broxburn	Autumn 2019	1.4	*10 hrs / 15 mins*	01/11/2022	01/02/2023	16:00	18:00	75.0	600.0	
Dynamic	SPD	Bathgate	Autumn 2019	2.0	*10 hrs / 15 mins*	01/11/2022	01/03/2023	08:30	20:00	25.0	600.0	
Dynamic	SPM	Connah's Quay	Autumn 2019	4.7	*10 hrs / 15 mins*	01/11/2022	01/03/2023	09:30	13:30	39.0	200.0	
Dynamic	SPM	Fiddlers Ferry	Autumn 2019	5.0	*10 hrs / 15 mins*	01/03/2022	01/11/2022	17:00	18:00	75.0	600.0	
Restore	SPM	Cellarhead	Autumn 2019	7.0	5 hrs / 15 mins	01/03/2022	01/11/2022	07:30	21:30	0.0	797.0	
Restore	SPM	Cellarhead	Autumn 2019	5.0	5 hrs / 15 mins	01/03/2022	01/11/2022	07:30	21:30	0.0	897.0	
Restore	SPM	Cellarhead	Autumn 2019	7.0	5 hrs / 15 mins	01/03/2022	01/11/2022	07:30	21:30	0.0	697.0	Bid with-drawn by provider
Restore	SPM	Cellarhead	Autumn 2019	7.0	5 hrs / 15 mins	01/03/2022	01/11/2022	07:30	21:30	0.0	497.0	
Restore	SPM	Cellarhead	Autumn 2019	7.0	5 hrs / 15 mins	01/03/2022	01/11/2022	07:30	21:30	0.0	597.0	

Table 82 Summary of tender results for successful bids in SPEN's DSO Flexibility auctions, for delivery years 2023/24 and 2024/25 [185]

Delivery year	**Number of providers**	**DNO Service**	**Location**	**Technologies**	**Tender**	**Individual provider MWs**	**Total MW**	**Run & response time**	**Availability fee, £/MW/h**	**Est. daily availability payment £/MW/day**	**Utilisation price, £/MWh**
2023/24	179	Secure and Sustain	Many, across both Licence areas	Demand, and fossil gas. Some had storage (apparently batteries or hydro) as a 2nd technology	Autumn 2020 & Spring 2021	0 to 4.8	21.8	1 to 12 hrs / 15 mins	£0 - £270	**£0 - £2,200**	£30-£500
2024/25	359	Secure and Sustain	Many, across both Licence areas	Demand, fossil gas and storage. Some demand had storage (apparently batteries or hydro) as a 2nd technology	Autumn 2020 & Spring 2021	0 to 4.8	51.5	1-24 hrs / 15 mins	£25 - £270	**£0 - £1,755**	£28 - £800

Annexes to Chapter 4
Battery wholesale trades: simulation methodology and results.

Figures for Chapter 4 Annexes

Tables for Chapter 4 Annexes

Chapter 4 Annex 1

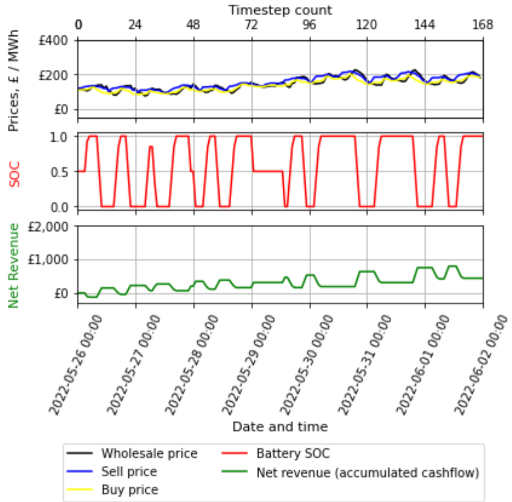
Battery simulation plots – by week

The following plots show the battery simulations for every week of the case study period. The parameters are all as shown in the table below.

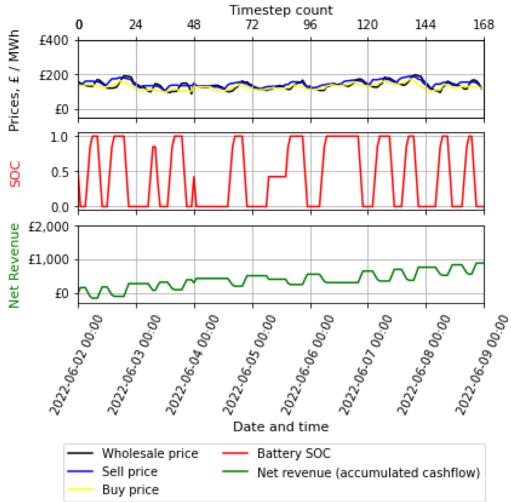
Table 83 Battery and trading parameters, 2 hour battery, "best cashflow" scenarios

Case study season	**Battery parameters**			**Scenario: Trading parameters**		**Scenario choice criterion**
	Pmax, MW	Duration, hr	Round trip efficiency	Visibility window, hr	Trading strategy	
Summer	1	2	85%	3	"25%" ("moderate")	"best cashflow"
Autumn	1	2	85%	3	"25%" ("moderate")	"best cashflow"
Winter	1	2	85%	3	"25%" ("moderate")	"best cashflow"

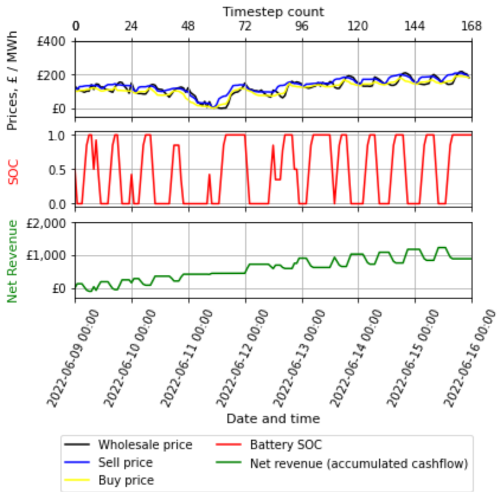
1.1. Summer battery timeseries plots - by week. “Best cashflow” scenario



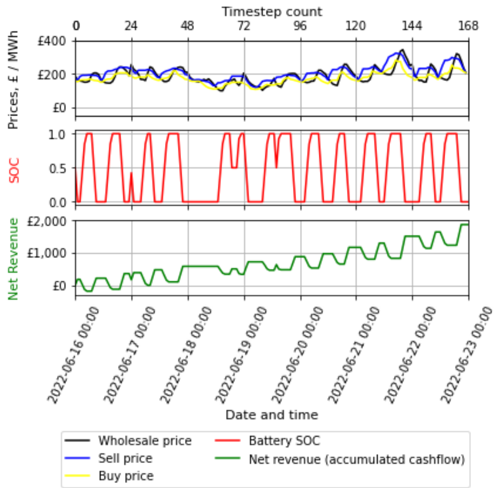
Week 1



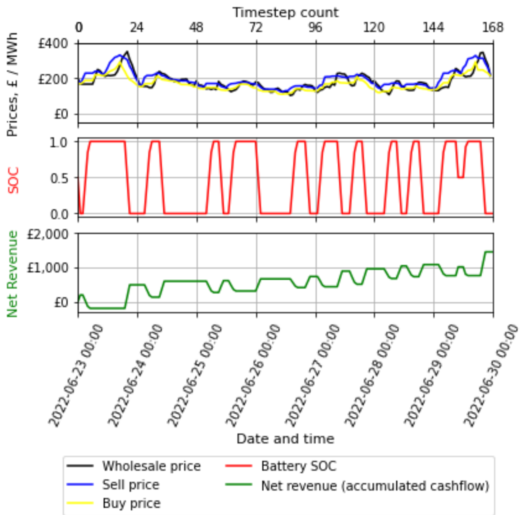
Week 2



Week 3



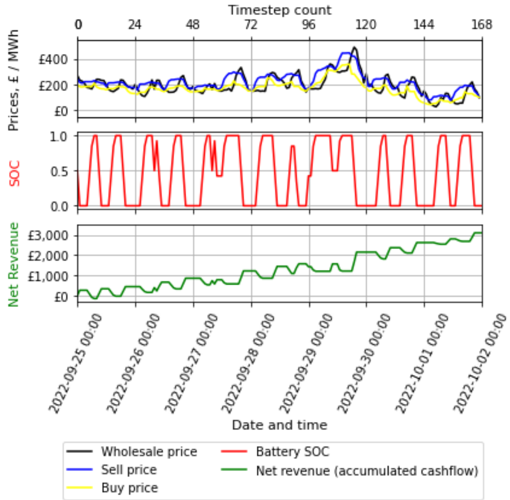
Week 4



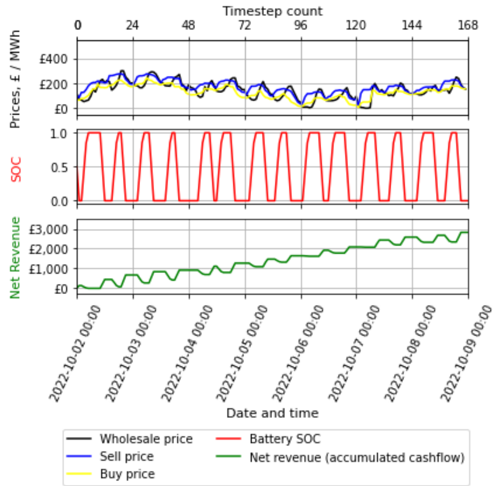
Week 5

Figure 127 Summer case study. Battery simulation, by week. “Best cashflow” scenario. Wholesale price, buy and sell prices, battery SOC and overall net revenue .

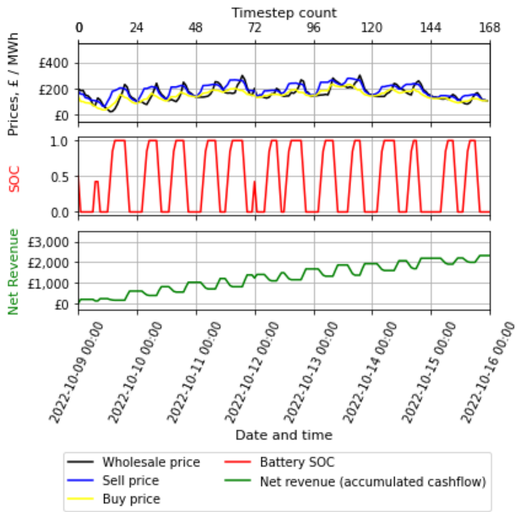
1.2. Autumn battery timeseries plots - by week. "Best cashflow" scenario



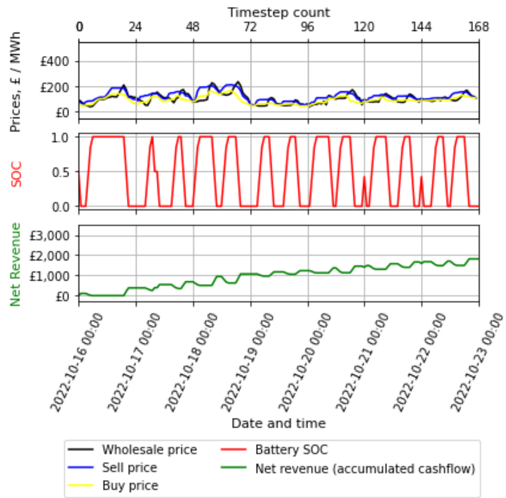
Week 1



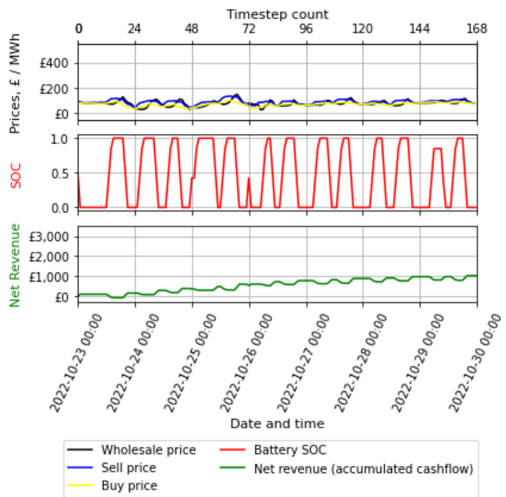
Week 2



Week 3



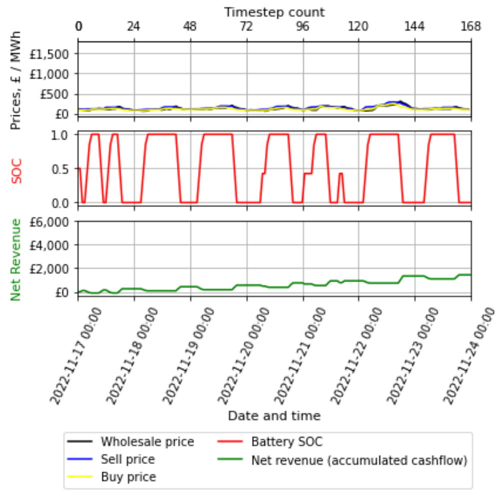
Week 4



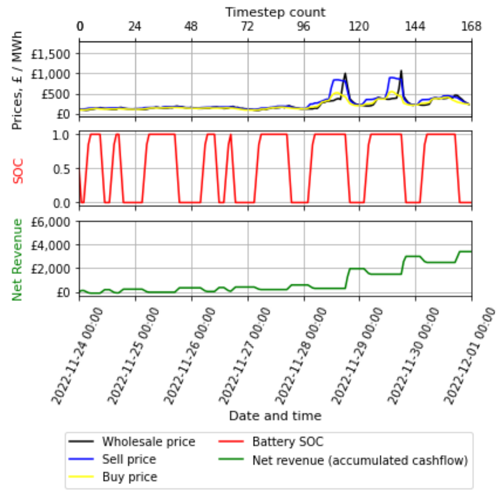
Week 5

Figure 128 Autumn case study. Battery simulation, by week. "Best cashflow" scenario. Wholesale price, buy and sell prices, battery SOC and overall net revenue.

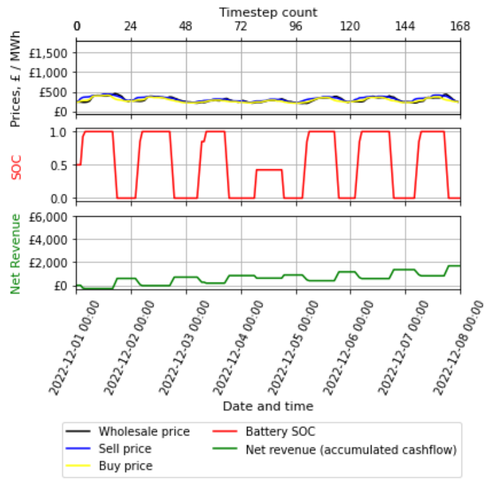
1.3. Winter battery timeseries plots by week. "Best cashflow" scenario – (full scale)



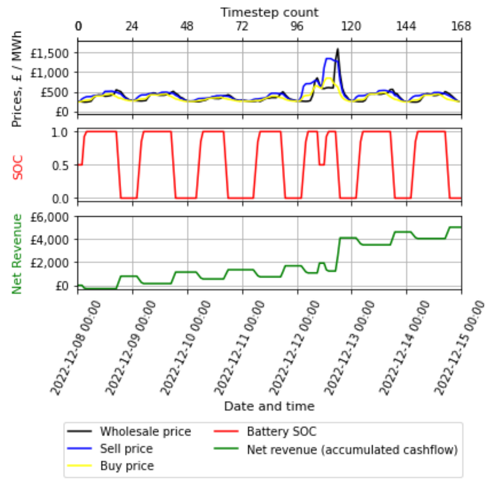
Week 1



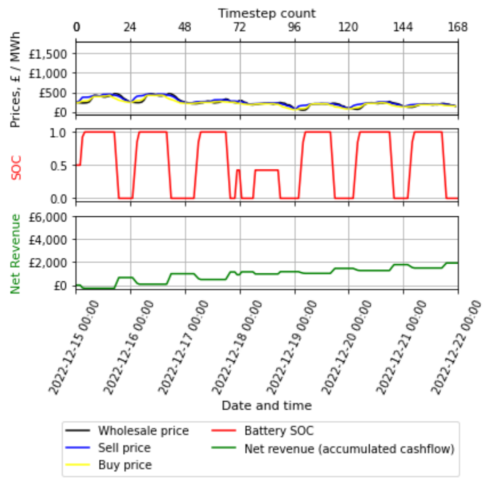
Week 2



Week 3



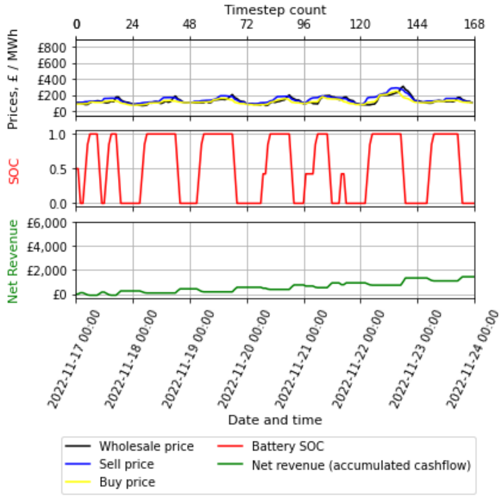
Week 4



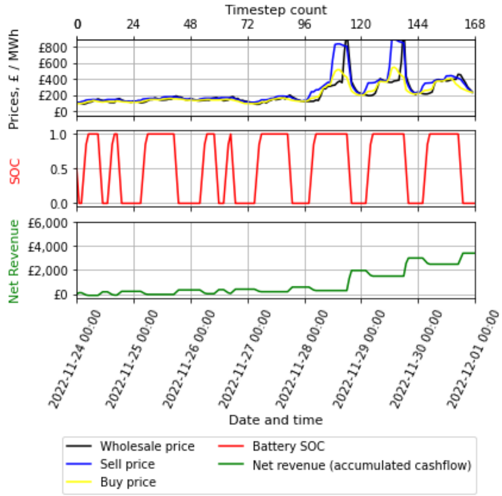
Week 5

Figure 129 Winter case study. Battery simulation, by week. "Best cashflow" scenario. Wholesale price, buy and sell prices, battery SOC and overall net revenue.

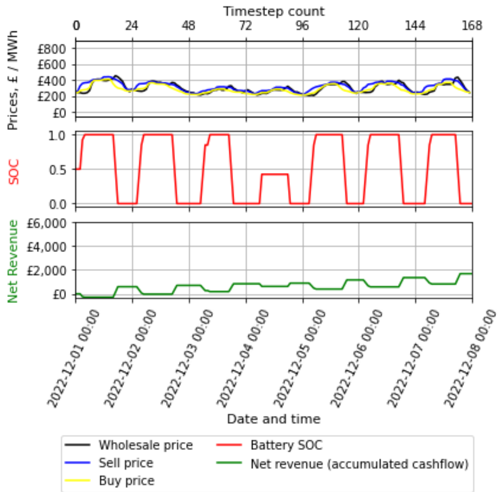
1.4. Winter battery timeseries plots - by week. “Best cashflow” scenario (larger price scale)



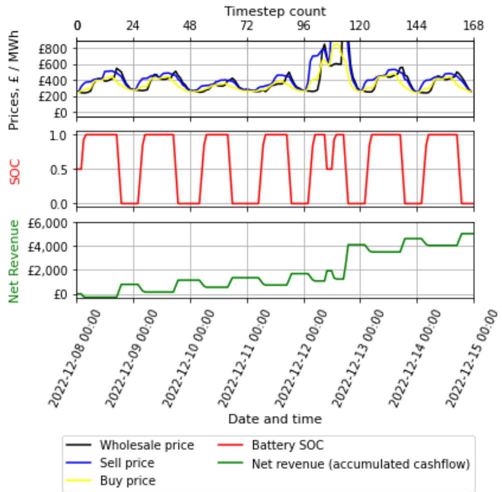
Week 1



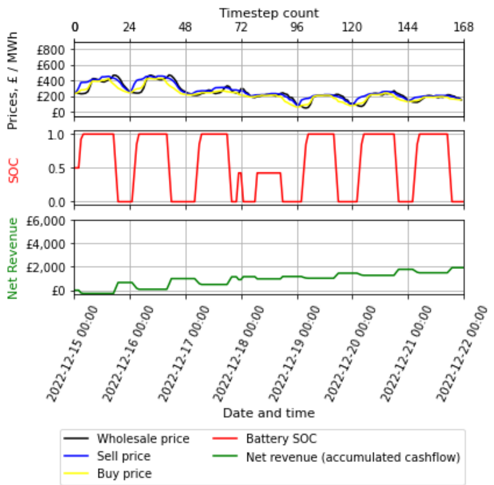
Week 2



Week 3



Week 4



Week 5

Figure 130 Winter case study. Battery simulation, by week. “Best cashflow” scenario. Wholesale price, buy and sell prices, battery SOC and overall net revenue. Enlarged scale for prices.

Chapter 4 Annex 2

Battery simulations, other trading parameters

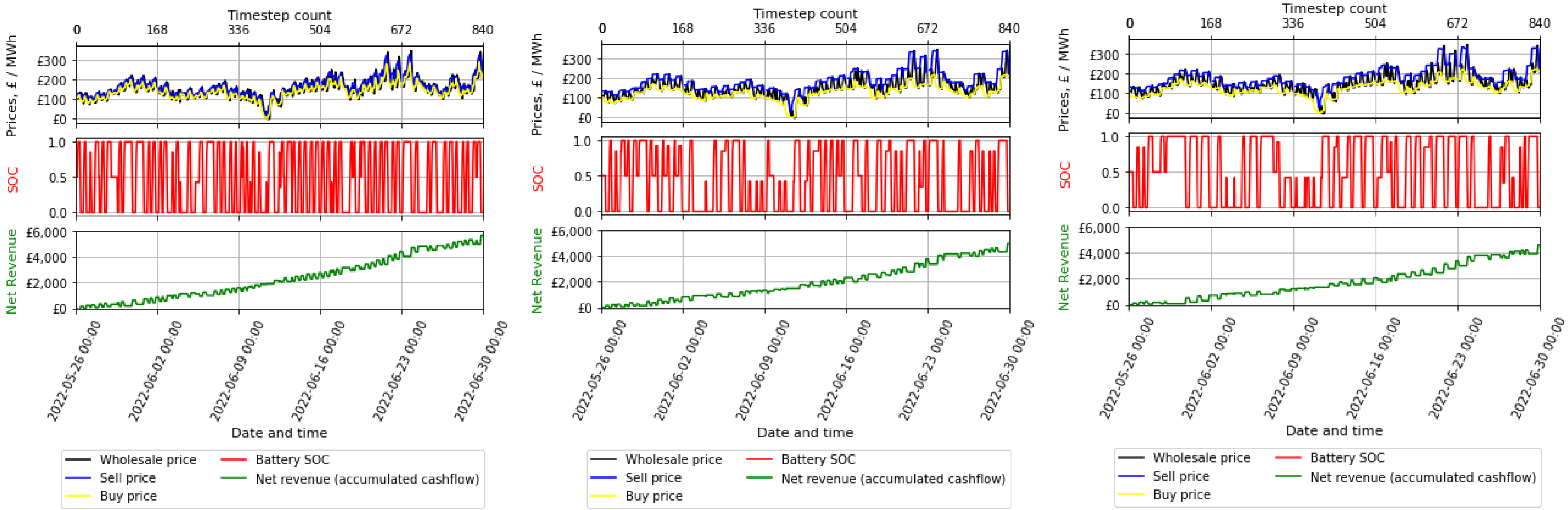
The following charts show the same battery (1 MW / 2 MWh, η= 85%), operating with different trading scenarios. The alternative scenarios restrict battery cycling to near 1 cycle per day on average across the case study.

Table 84 Battery and trading parameters, for 2 hour battery. "Best cashflow", "lower cycling" and "hard 1 cycle per day" scenarios

Case study season	Battery parameters		Scenario: Trading parameters		Results				Figure
	Duration, hr	Round trip efficiency	Visibility window, hr	Trading strategy	Scenario chosen	Ranked	Average cycles / day	Average net revenue / day	
Summer	2	85%	3	"25%" ("moderate")	"Best cashflow"	1	1.70	£157	Figure 131
			5	"5%" ("best price")	"Lower cycling"	2	1.18	£137	
			6	"10%" ("good price")	"Hard 1 cycle/ day limit"	3	0.97	£126	
Autumn	2	85%	3	"25%" ("moderate")	"Best cashflow"	1	1.99	£300	Figure 132
			5	"5%" ("best price")	"Lower cycling"	2	1.18	£241	
			6	"10%" ("good price")	"Hard 1 cycle/ day limit"	3	0.99	£215	
Winter	2	85%	3	"25%" ("moderate")	"Best cashflow"	1	1.11	£354	Figure 133
			3	"40" ("busy")	"Lower cycling"	2	0.97	£351	
			4	"5%" ("best price")	"Alternative lower-cycling"	3	1.04	£344	

2.1 Timeseries plots of battery activity: base case battery, best cashflow and lower cycling scenarios

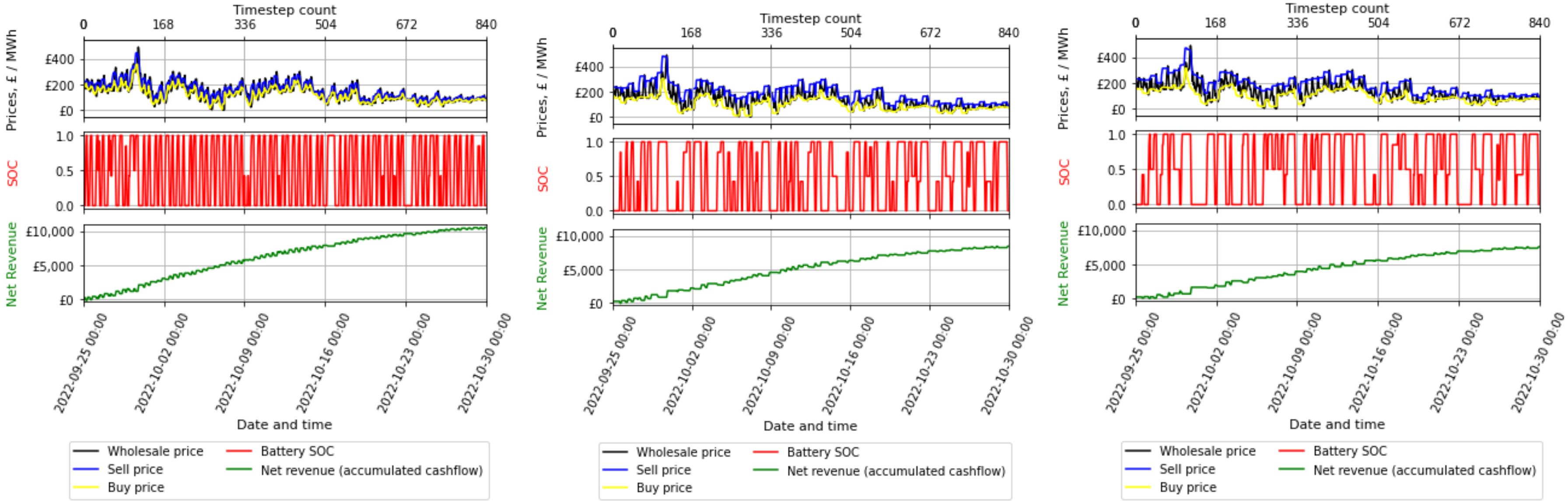
2.1.1 Summer, 2-hour battery, 3 battery simulations, alternative scenarios



(a) (b) (c)

Figure 131 Summer: battery simulations, 3 trading scenarios: (a) “best cashflow” ; (b) “lower cycling”; (c) “hard 1 cycle /day limit. Timeseries of wholesale price, buy and sell prices battery SOC and overall cashflow . Parameters as shown in Table 84

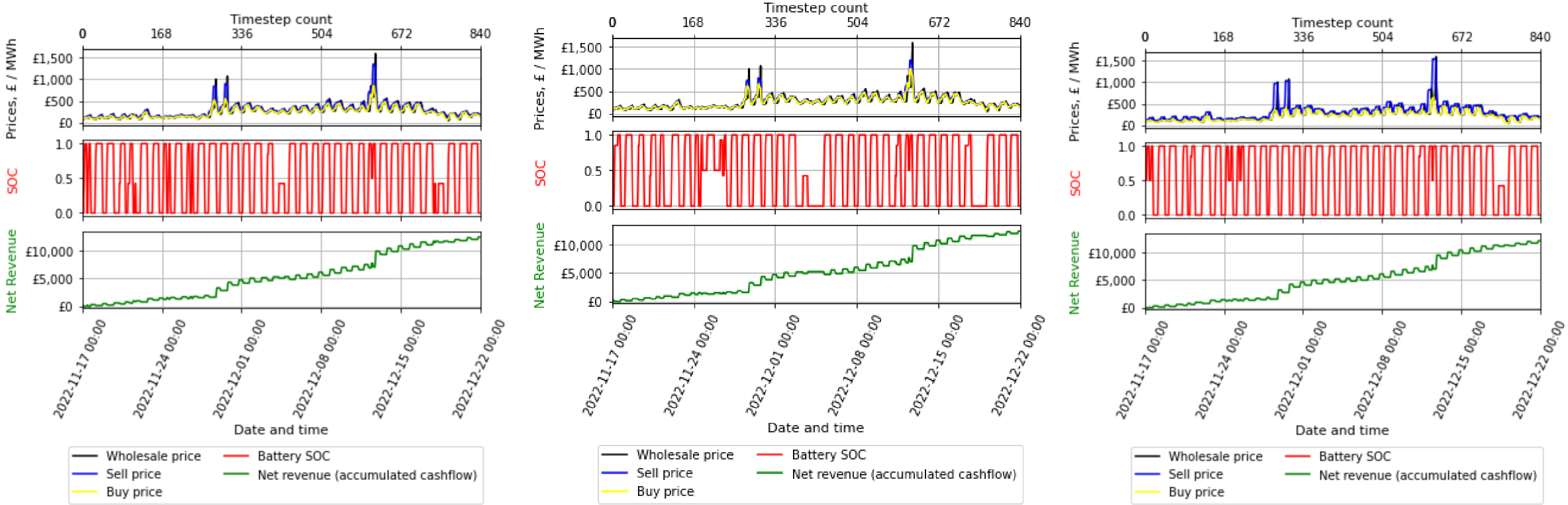
2.1.2 *Autumn, 2-hour battery, 3 battery simulations, alternative scenarios*



(a) (b) (c)

Figure 132 Autumn, battery simulations, 3 trading scenarios: (a) “best cashflow” ; (b) “lower cycling”; (c) “hard 1 cycle /day limit. Timeseries of wholesale price, buy and sell prices, battery SOC and overall cashflow. Parameters as shown in Table 84

2.1.3 Winter, 2-hour battery, 3 battery simulations, alternative scenarios



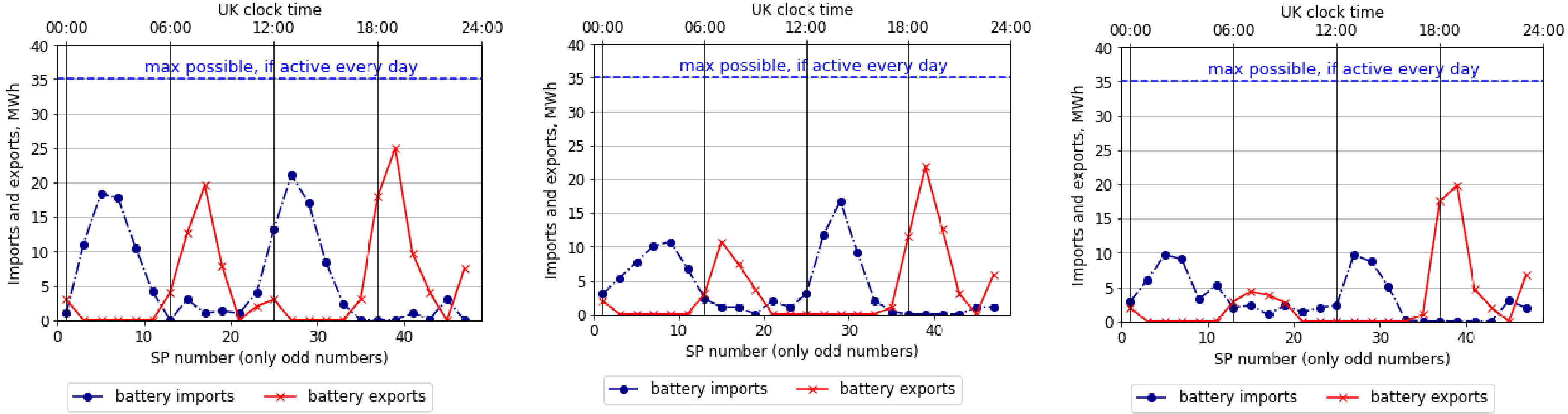
(a) (b) (c)

Figure 133 Winter, battery simulations, 3 trading scenarios: (a) “best cashflow” ; (b) “lower cycling (< 1 cycle / day)”; (c) alternative lower-cycling scenario. Timeseries of wholesale price, buy and sell prices, battery SOC and overall cashflow . Parameters as shown in Table 84

2.2 Battery activity by time of day: base case battery, best cashflow and lower cycling scenarios

The charts below show the aggregate MWh per SP over the whole of the case study period. Only odd numbered SPs are shown beca use the data are aggregated to model with 1-hour resolution wholesale price data.

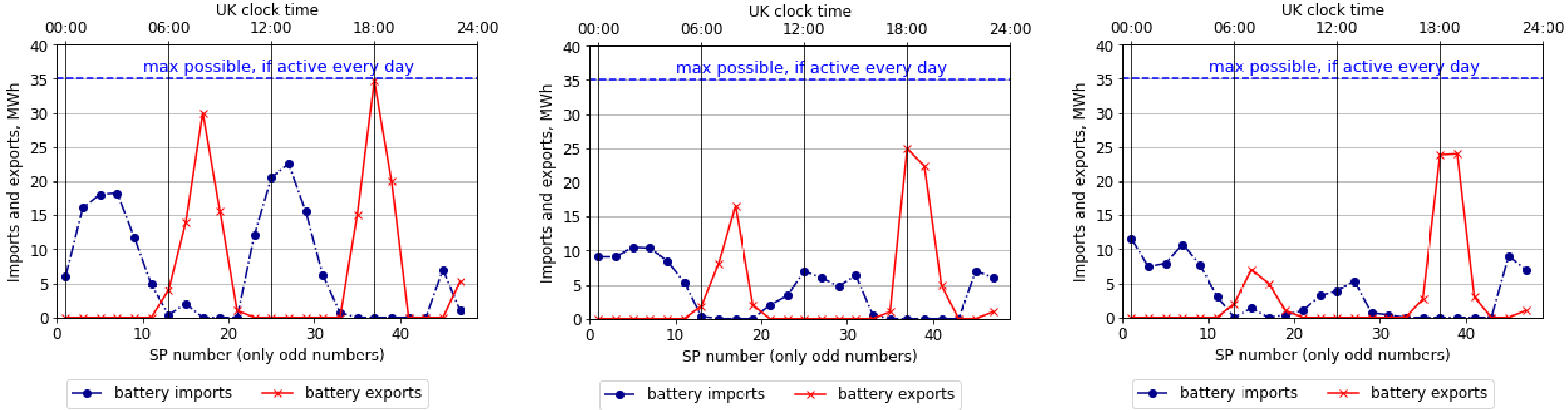
2.2.1 Summer case study



(a) Best cashflow (b) Lower cycling (c) Lowest cycling

Figure 134 Simulated aggregate battery activity by Settlement Period, Summer, "best cashflow" and lower cycling scenarios

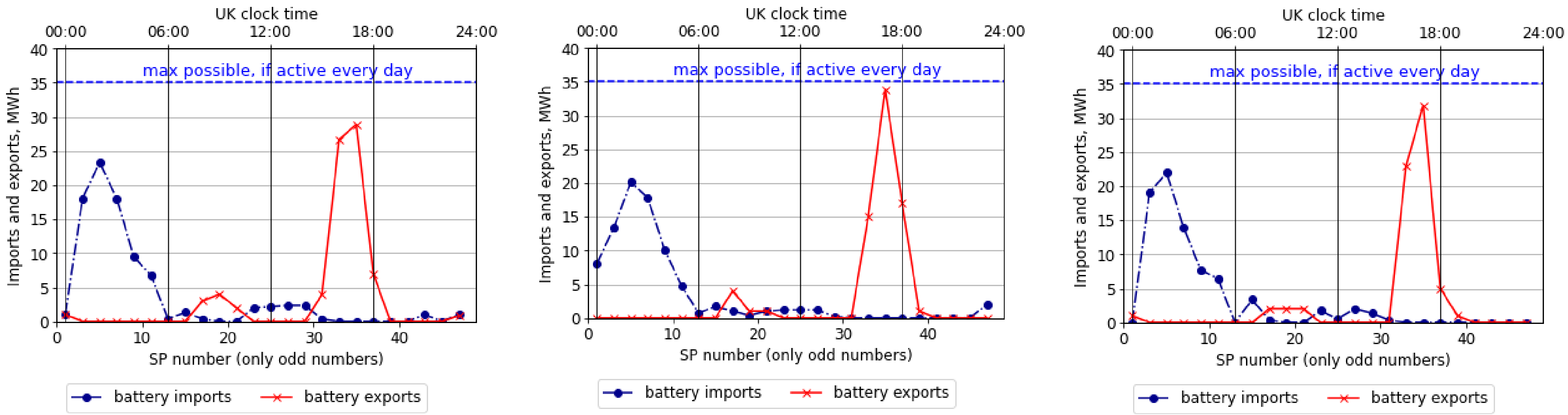
2.2.2 Autumn case study



Best cashflow | Lower cycling | Lowest cycling

Figure 135 Simulated aggregate battery activity by Settlement Period, Autumn, “best cashflow” and lower cycling scenarios

2.2.3 Winter case study



Best cashflow | Lower cycling | Lowest cycling

Figure 136 Simulated aggregate battery activity by Settlement Period, Winter, “best cashflow” and lower cycling scenarios

Chapter 4 Annex 3

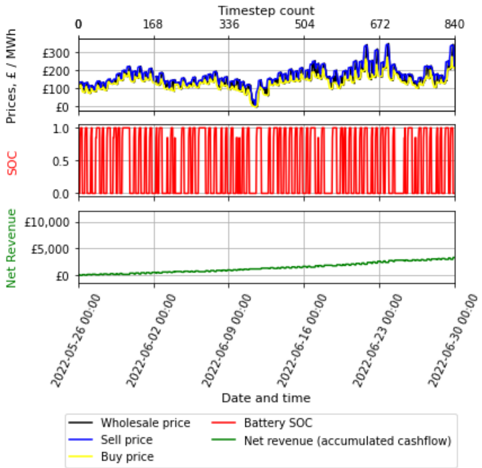
Battery simulations: other battery parameters.

The following charts show a 1 MW battery of other durations, selecting the "best cashflow" scenario in each case.

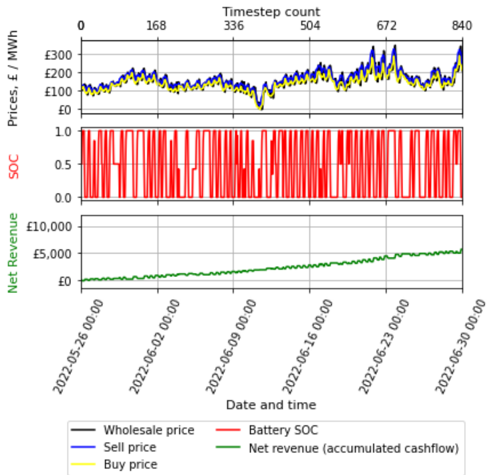
Table 85 The effect of battery duration on battery cycling behaviour and net revenues. Selected parameters, scenarios and results.

Case study season	Battery parameters			Scenario: Trading parameters					Figure
	Duration, hr	Round trip efficiency	Scenario chosen	Visibility window, hr	Trading strategy	Average cycles / day	Average net revenue / day	Average net revenue / day.MWh	
Summer	1	85%	Best cashflow	3	5% , "best price"	1.85	£91.15	£91.15	Figure 137
	2	85%	Best cashflow	3	25%, "moderate"	1.70	£156.74	£78.37	
	4	85%	Best cashflow	4	25% "moderate"	1.39	£236.78	£59.20	
	12	85%	Best cashflow	10	40% "busy"	0.46	£296.65	£24.72	
	12	70%	Best cashflow	21	25% "moderate"	0.22	£156.62	£13.05	
Autumn	1	85%	Best cashflow	2	10% / good price	2.12	£174.63	£174.63	Figure 139
	2	85%	Best cashflow	3	25% / "moderate"	1.99	£300.36	£150.18	
	4	85%	Best cashflow	4	40% / "busy"	1.52	£427.89	£106.97	
	12	85%	Best cashflow	10	40% "busy"	0.51	£502.50	£41.88	
	12	70%	Best cashflow	22	40% "busy"	0.31	£334.95	£27.91	
Winter	1	85%	Best cashflow	3	5% / best price	1.19	£208.97	£208.97	Figure 141
	2	85%	Best cashflow	3	25% / "moderate"	1.11	£354.08	£177.04	
	4	85%	Best cashflow	4	40% / "busy"	0.94	£541.23	£135.31	
	12	85%	Best cashflow	9	40% / "busy"	0.50	£724.75	£60.73	
	12	70%	Best cashflow	9	40% / "busy"	0.26	£441.16	£36.76	

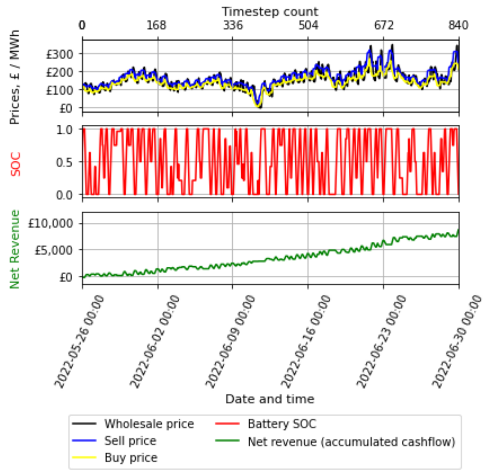
Annex 3.1. Summer, batteries of 1, 2, 4 and 12 hour duration (85% round-trip), and 12 hour duration (70% round-trip). Best cashflow scenarios



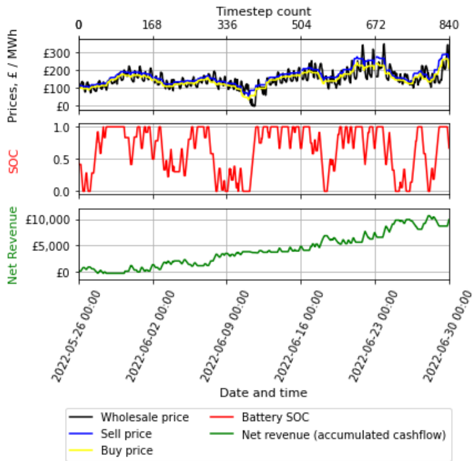
(a) 1-hour 85% η battery



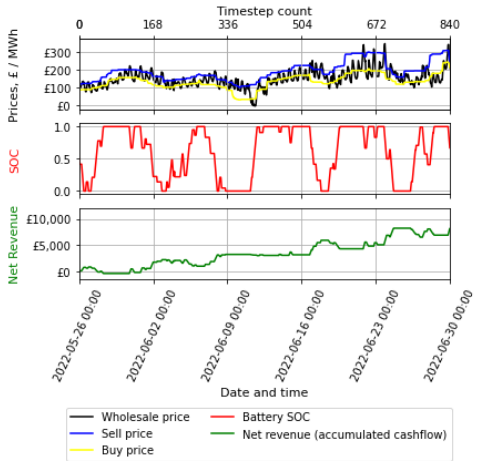
(b) 2-hour 85% η battery



(c) 4-hour 85% η battery

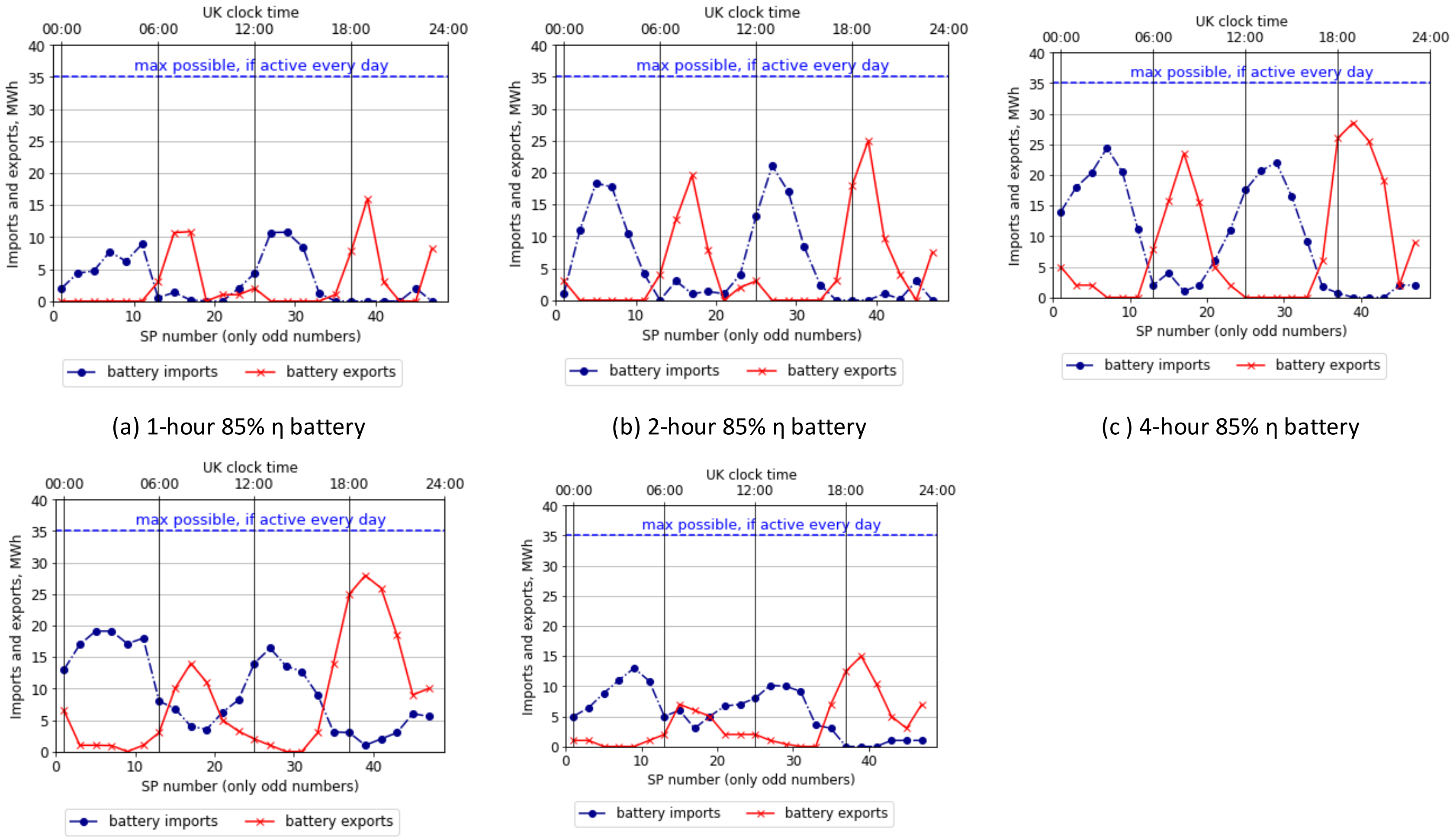


(d) 12-hour 85% η battery



(e) 12-hour 70% η battery

Figure 137 Timeseries plots of wholesale price, battery SOC and overall net revenue, for 1 MW battery (a) 1-hour, (b) 2-hour, (c) 4-hour, (d) and (e) 12-hour. (a) to (d) battery round-trip efficiency 85%; (e) 70%, Summer, all “best cashflow” scenarios.



(a) 1-hour 85% η battery

(b) 2-hour 85% η battery

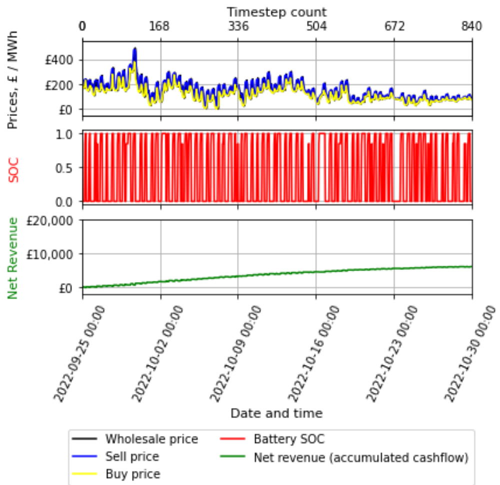
(c) 4-hour 85% η battery

(d) 12-hour 85% η battery

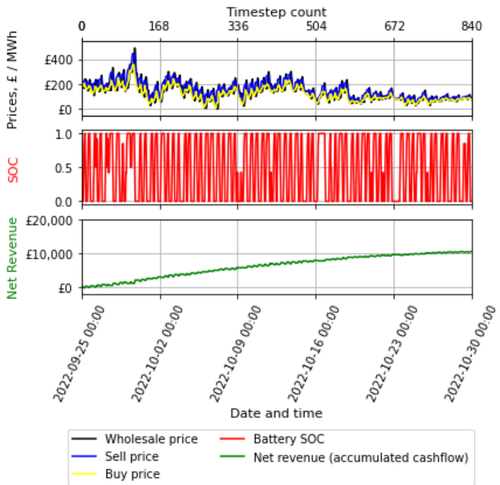
(e) 12-hour 70% η battery

Figure 138 Battery activity by time of day (Settlement Period) plots, for 1 MW battery (a) 1-hour, (b) 2-hour, (c) 4-hour, (d) and (e) 12-hour. (a) to (d) battery round-trip efficiency 85%; (e) 70%, Summer, all “best cashflow” scenarios.

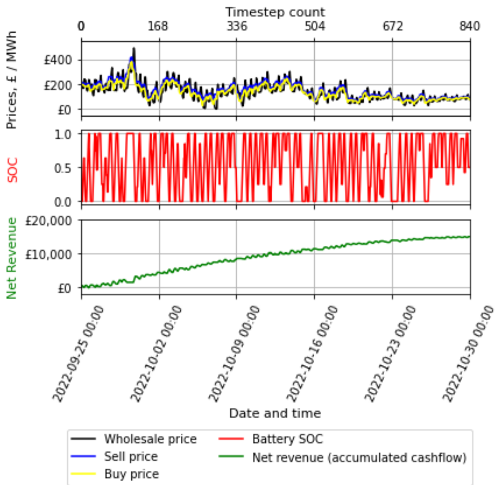
Annex 3.2. Autumn, batteries of 1, 2, 4 and 12 hour duration (85% round-trip), and 12 hour duration (70% round-trip). best cashflow scenarios



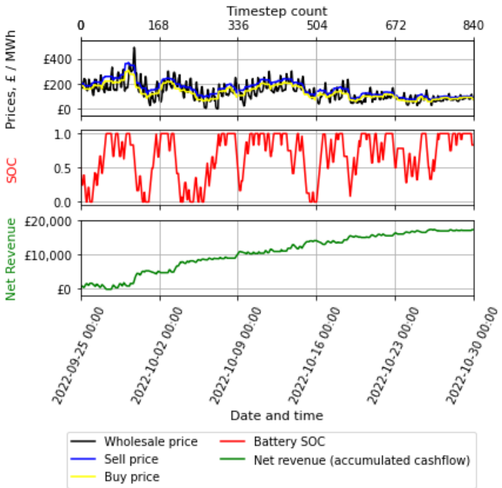
(a) 1-hour 85% η battery



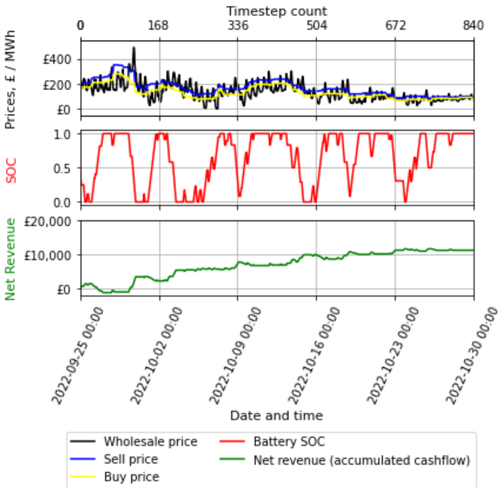
(b) 2-hour 85% η battery



(c) 4-hour 85% η battery

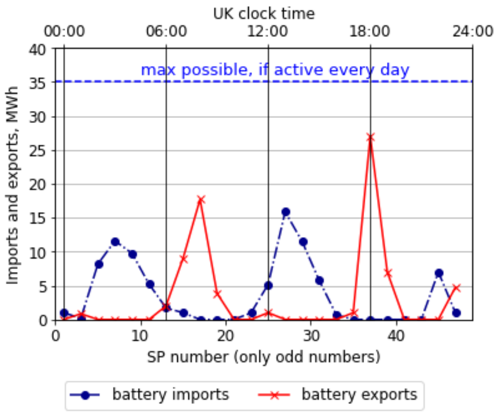


(d) 12-hour 85% η battery

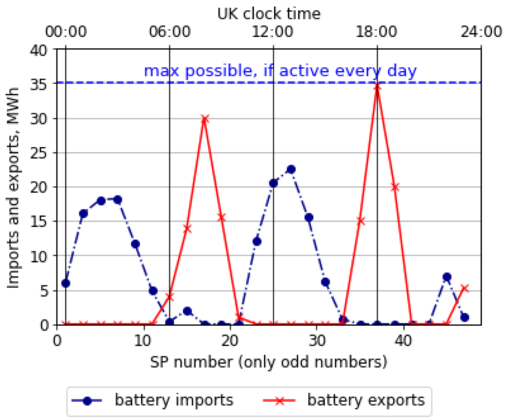


(e) 12-hour 70% η battery

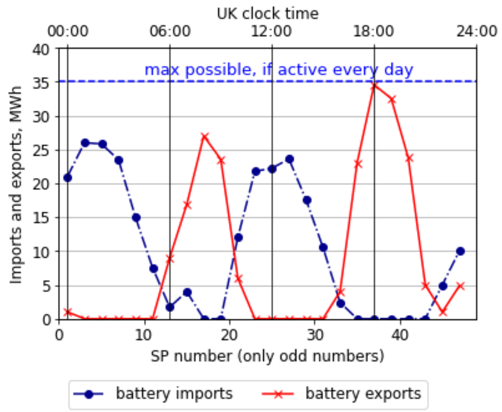
Figure 139 Timeseries plots of wholesale price, battery SOC and overall net revenue, for 1 MW battery (a) 1-hour, (b) 2-hour, (c) 4-hour, (d) and (e) 12-hour. (a) to (d) battery round-trip efficiency 85%; (e) 70%, Autumn, all “best cashflow” scenarios.



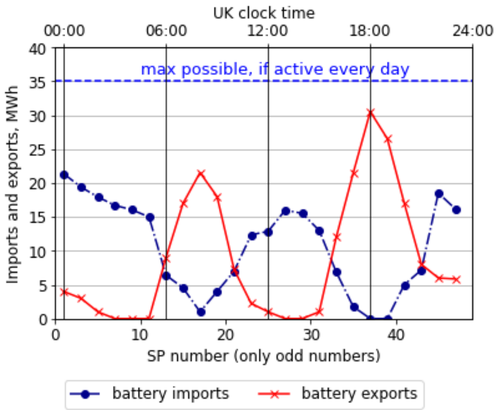
(a) 1-hour 85% η battery



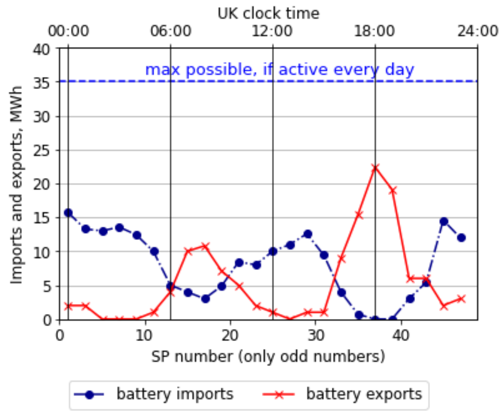
(b) 2-hour 85% η battery



(c) 4-hour 85% η battery



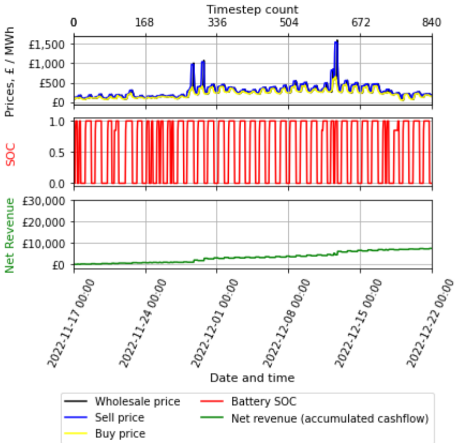
(d) 12-hour 85% η battery



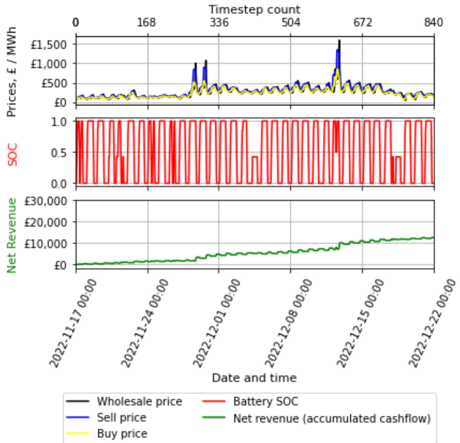
(e) 12-hour 70% η battery

Figure 140 Battery activity by time of day (Settlement Period) plots, for 1 MW battery (a) 1-hour, (b) 2-hour, (c) 4-hour, (d) and (e) 12-hour. (a) to (d) battery round-trip efficiency 85%; (e) 70%, Autumn, all “best cashflow” scenarios.

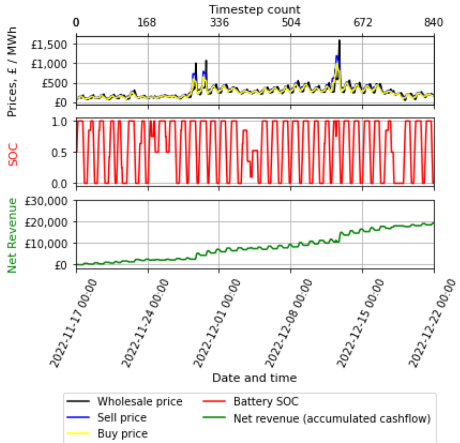
Annex 3.3. Winter, batteries of 1, 2, 4 and 12 hour duration (85% round-trip), and 12 hour duration (70% round-trip). Best cashflow scenarios



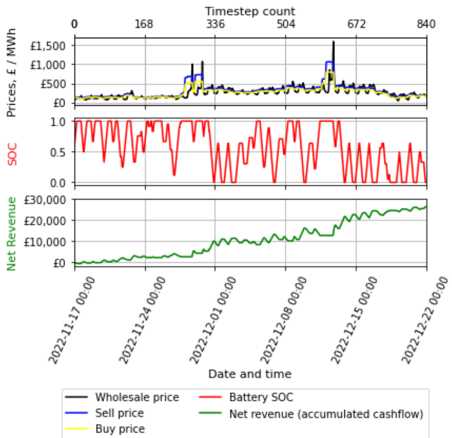
(a) 1-hour 85% η battery



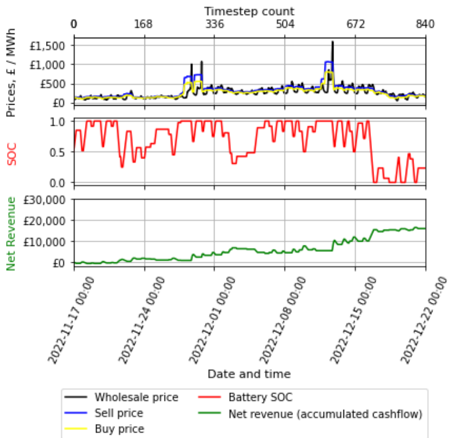
(b) 2-hour 85% η battery



(c) 4-hour 85% η battery

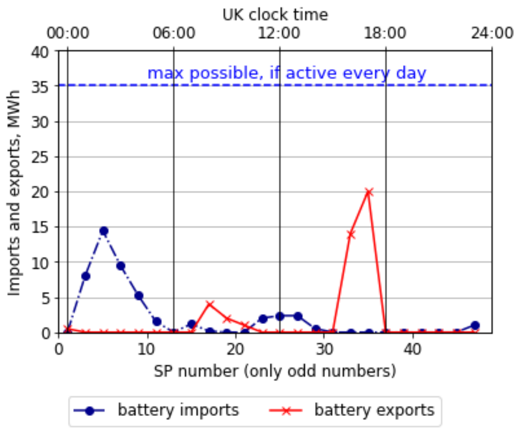


(d) 12-hour 85% η battery

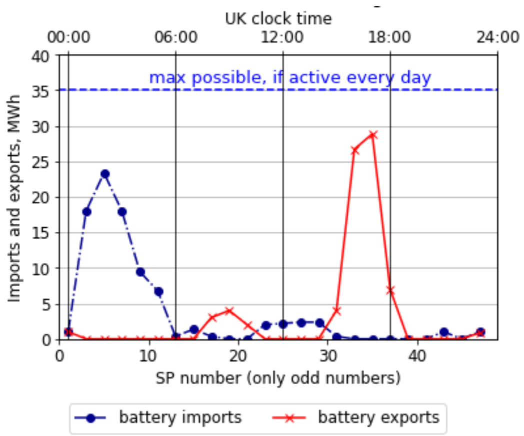


(e) 12-hour 70% η battery

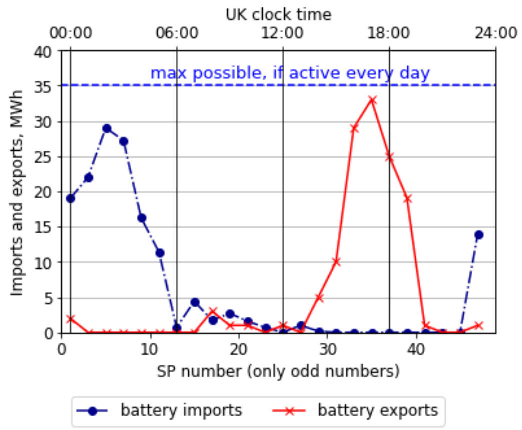
Figure 141 Timeseries plots of wholesale price, battery SOC and overall net revenue, for 1 MW battery (a) 1-hour, (b) 2-hour, (c) 4-hour, (d) and (e) 12-hour. (a) to (d) battery round-trip efficiency 85%; (e) 70%, Winter, all "best cashflow" scenarios.



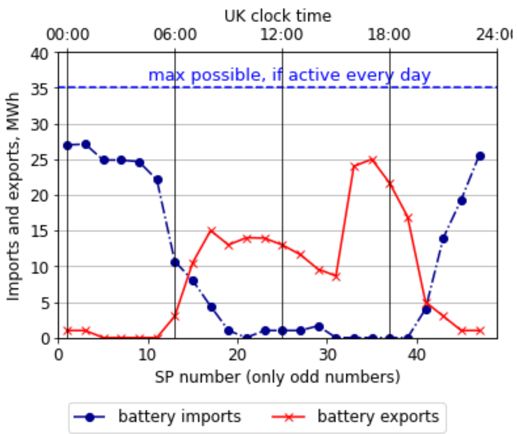
(a) 1-hour 85% η battery



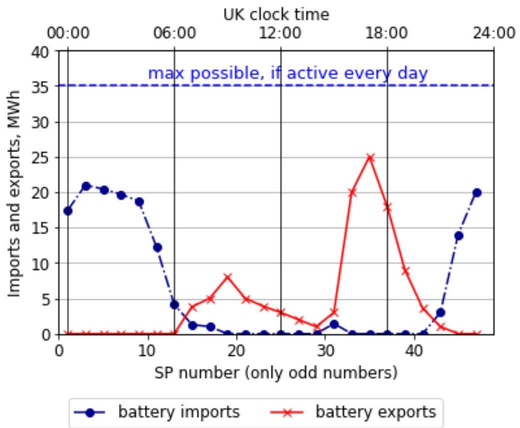
(b) 2-hour 85% η battery



(c) 4-hour 85% η battery



(d) 12-hour 85% η battery



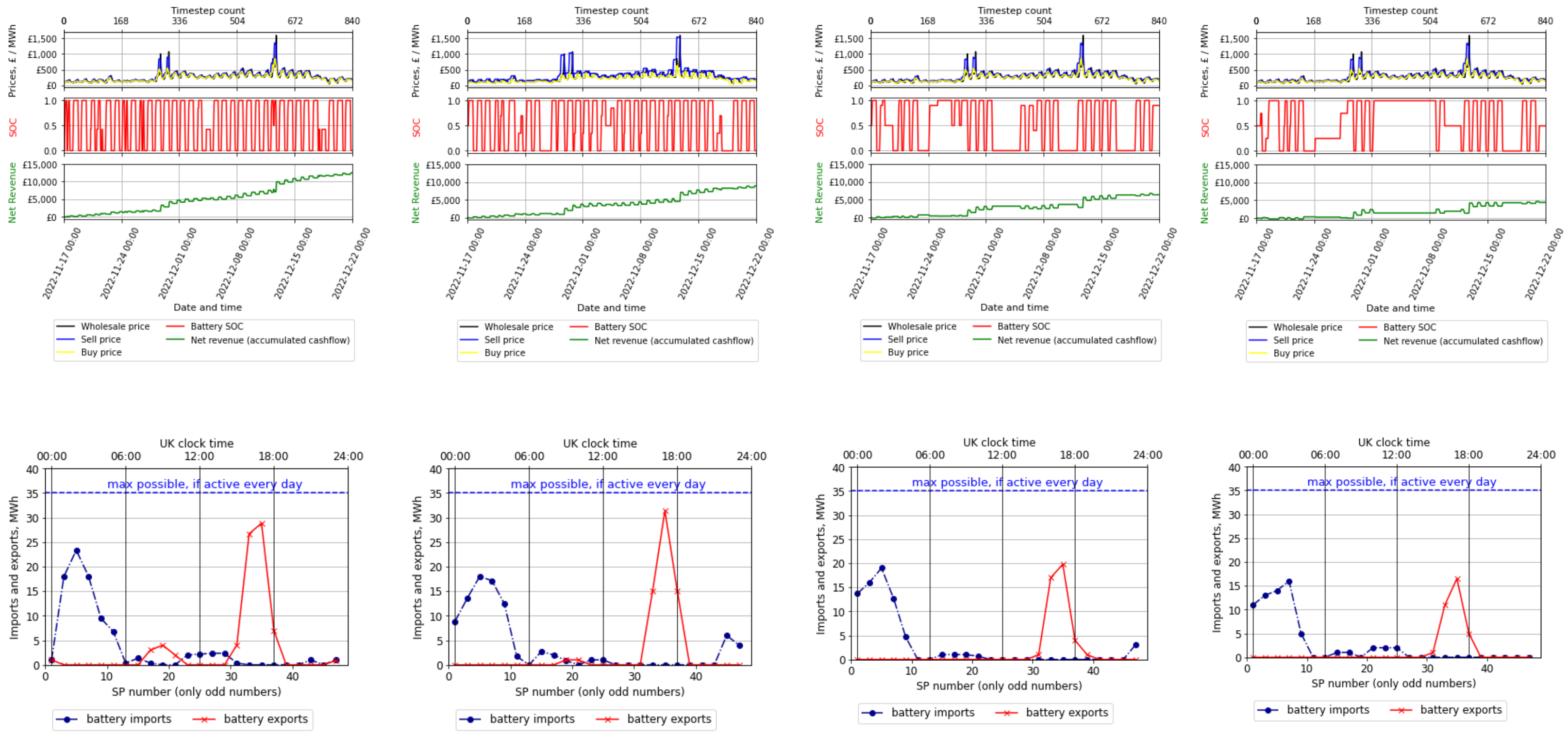
(e) 12-hour 70% η battery

Figure 142 Battery activity by time of day (Settlement Period) plots, for 1 MW battery (a) 1-hour, (b) 2-hour, (c) 4-hour, (d) and (e) 12-hour. (a) to (d) battery round-trip efficiency 85%; (e) 70%, Winter, all “best cashflow” scenarios.

Annex 3.4. Batteries of 2 hour duration, round-trip efficiencies of 85% (base case), 70%, 60% and 50%. Best cashflow scenarios

Table 86 The effect of battery round-trip efficiency on battery cycling behaviour and net revenues. Selected parameters and scenarios and results.

Case study season	Battery parameters		Scenario chosen (“best cashflow” vs “lower cycling” etc.)	Trading scenario: trading parameters		Results: Battery cycling and net revenue		
	Duration, hr	Round trip efficiency		Visibility window, hr	Trading strategy	Average battery cycles / day	Average net revenue / day	Average net revenue / day .MWh
Winter	2	85%	Best cashflow	3	25% / “moderate”	1.11	£354.08	£177.04
		70%	Best cashflow	5	5% / “best price”	0.91	£251.53	£125.77
		60%	Best cashflow	4	25% / “moderate”	0.61	£186.97	£93.49
		50%	Best cashflow	4	25% / “moderate”	0.48	£107.61	£63.14



(a) 2-hour 85% η battery (b) 2-hour 70% η battery (c) 2-hour 60% η battery (d) 2-hour 50% η battery

Figure 143 The effect of increased round-trip losses on simulated battery activity. Winter. 2-hour batteries, best cashflow scenarios, round-trip efficiencies from 85% to 50%. Top row: battery activity timeseries; bottom row - plots of aggregated imports and exports by time of day (Settlement Period).

Chapter 4 Annex 4

Comparison of overall cashflows of batteries of different durations

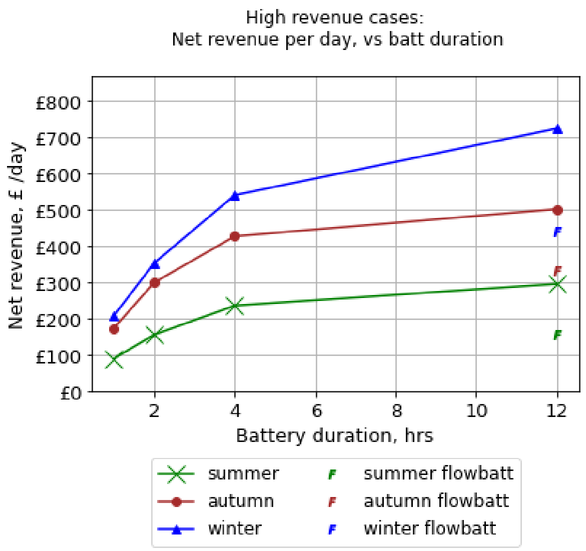
Table 87 Battery and trading parameters for best cashflow and lowest cycling scenarios, daily net revenues and battery cycling. Batteries 1-12 hours duration, 85% round trip efficiency, and 12-hour "flow battery" of 70% round-trip efficiency

Case study season	Battery parameters		Scenario parameters		Results			Scenario type
	Duration, hrs	Round -trip	Visibility window	Trading strategy	Net revenue, average £/ day over the whole case study season	Net revenue per MWh batt capacity, average £/(day. batt MWh)	Battery cycling: Average battery cycles / day	
summer	1	85%	3	5% / "best price"	£91.15	£91.15	1.85	Best cashflow
	1	*85%*	*6*	*5% / "best price"*	*£69.70*	*£69.70*	*0.99*	*Lowest cycling*
	2	85%	3	25% "moderate"	£156.74	£78.37	1.70	Best cashflow
	2	*85%*	*6*	*10% "good price"*	*£126.00*	*£63.00*	*0.97*	*Lowest cycling*
	4	85%	4	25% / "moderate"	£236.78	£59.20	1.39	Best cashflow
	4	*85%*	*5*	*10% "good price"*	*£215.41*	*£53.85*	*0.97*	*Lowest cycling*
	12	85%	10	40% "busy"	£296.65	£24.72	0.46	Best cashflow is low cycling
	12	70%	21	25% "moderate"	£156.62	£13.05	0.22	
autumn	1	85%	2	10% / good price	£174.63	£174.63	2.12	Best cashflow
	1	*85%*	*7*	*10% / good price*	*£111.98*	*£111.98*	*0.95*	*Lowest cycling*
	2	85%	3	25% / "moderate"	£300.36	£150.18	1.99	Best cashflow
	2	*85%*	*6*	*10% / good price*	*£215.47*	*£107.74*	*0.99*	*Lowest cycling*
	4	85%	4	40% / "busy"	£427.89	£106.97	1.52	Best cashflow
	4	*85%*	*6*	*25% "moderate"*	*£359.92*	*£89.98*	*0.96*	*Lowest cycling*
	12	85%	10	40% "busy"	£502.50	£41.88	0.51	Best cashflow is low cycling
	12	70%	22	40% "busy"	£334.95	£27.91	0.31	
winter	1	85%	3	5% / best price	£208.97	£208.97	1.19	Best cashflow
	1	*85%*	*5*	*5% / best price*	*£201.05*	*£201.05*	*1.00*	*Lowest cycling*
	2	85%	3	25% / "moderate"	£354.08	£177.04	1.11	Best cashflow
	2	*85%*	*3*	*40% "busy"*	*£350.60*	*£175.30*	*0.97*	*Lowest cycling*
	4	85%	4	40% / "busy"	£541.23	£135.31	0.94	Best cashflow is low cycling
	12	85%	9	40% / "busy"	£724.75	£60.73	0.50	
	12	70%	9	40% / "busy"	£441.16	£36.76	0.26	

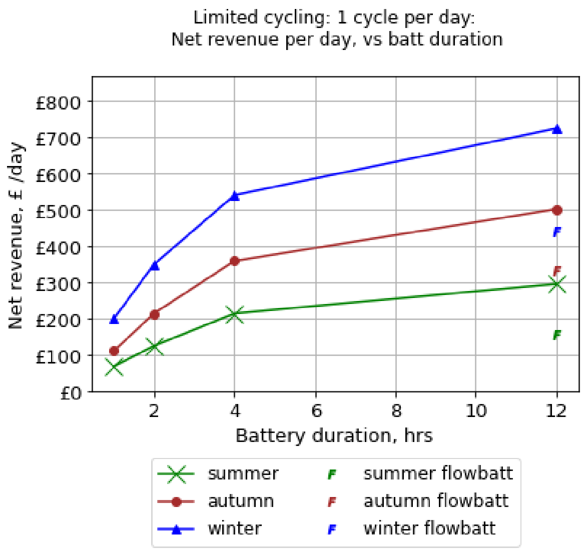
Best cashflow cycling scenarios

Lowest cycling scenarios:

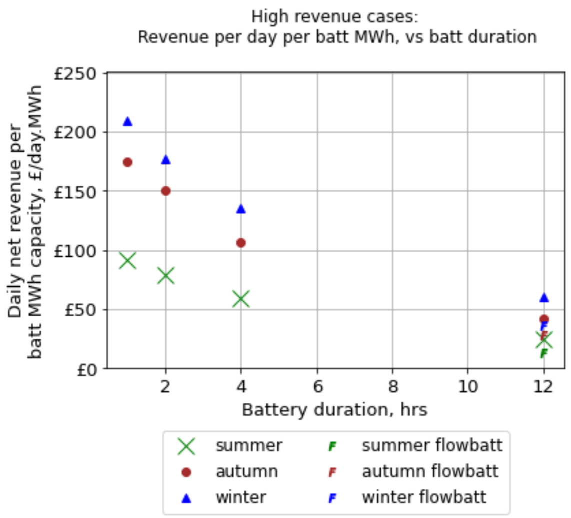
1 cycle per day max



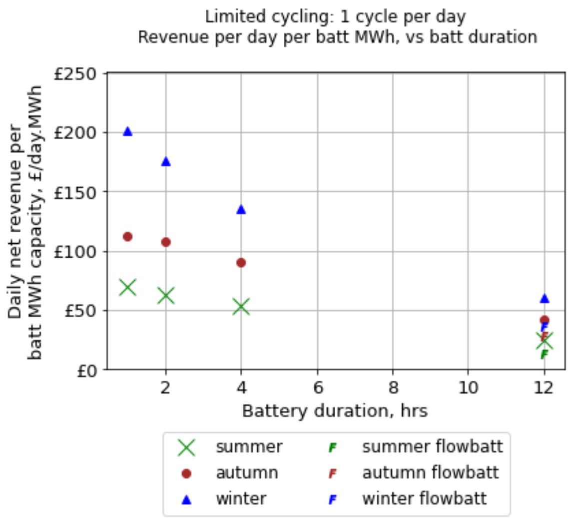
(a)



(b)



(c)



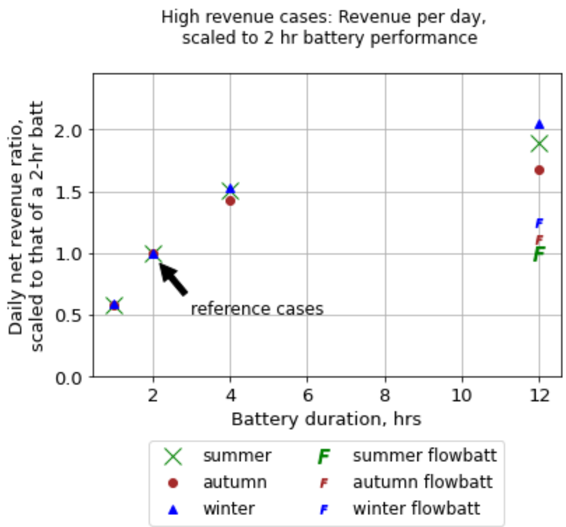
(d)

Figure 144 (a) and (b): battery daily net revenues (£ / day) (c) and (d): daily net revenues per MWh battery capacity (£/day. MWh). All vs battery duration, for 85% η batteries, and "flow battery", 12 hour, 70% η. (a) and (c): best cashflow scenarios; (b) and (d): lowest cycling scenarios (hard 1-battery-cycle-per-day limit).

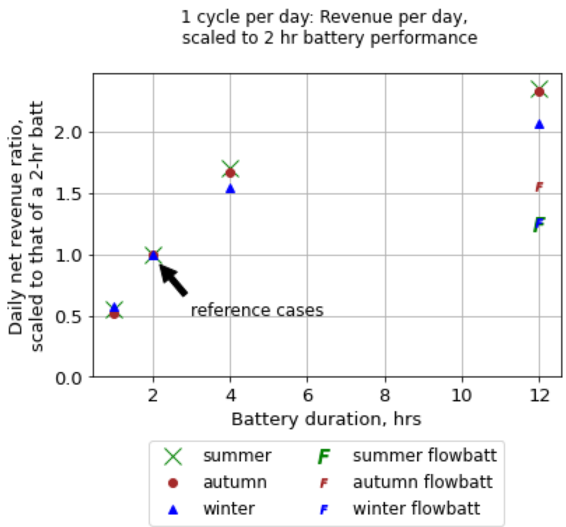
Best cashflow cycling scenarios

Lowest cycling scenarios:

1 cycle per day max



(a)



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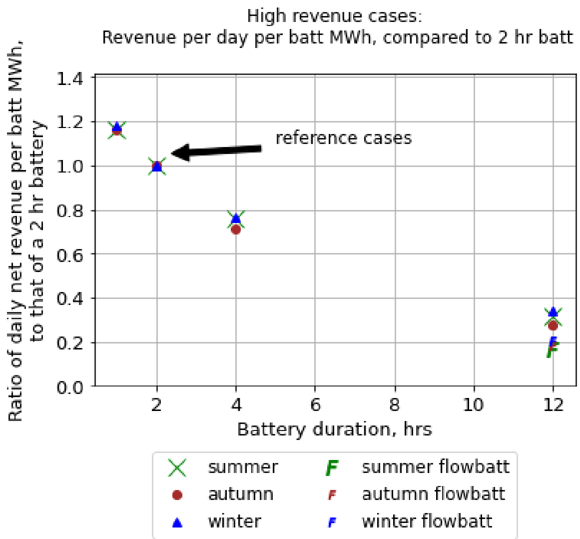
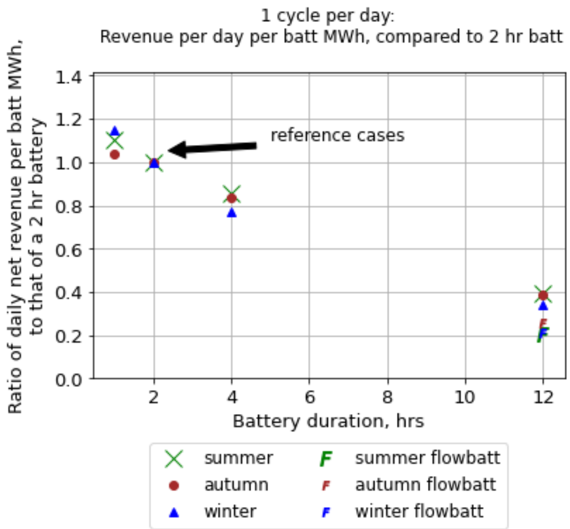


(c)



(d)

Figure 145 Ratios of net revenues from batteries of all durations, to that of a 2-hour battery. (a) and (b): battery daily net revenues (£ / day) / daily net revenue of a 2 hour battery. (c) and (d): daily net revenues per MWh battery capacity (£/day. MWh) / daily net revenue per MWh of battery capacity of a 2 hour battery. All vs battery duration, for 85% η batteries, and "flow battery", 12 hour, 70% η. (a) and (c): all batteries - best cashflow scenarios; (b) and (d): all batteries - lowest cycling scenarios (hard 1-battery-cycle-per-day limit).

Chapter 4 Annex 5
Timeseries of selected real grid-connected batteries

Summer week 2

Cowley, Hutton and Pen y Cymoedd batteries, compared to battery simulations

4 June:

- As per simulation, all 3 batts have a morning of little / no activity, followed by a midday / early afternoon import
- Cowley battery alone performs the early evening export that is simulated

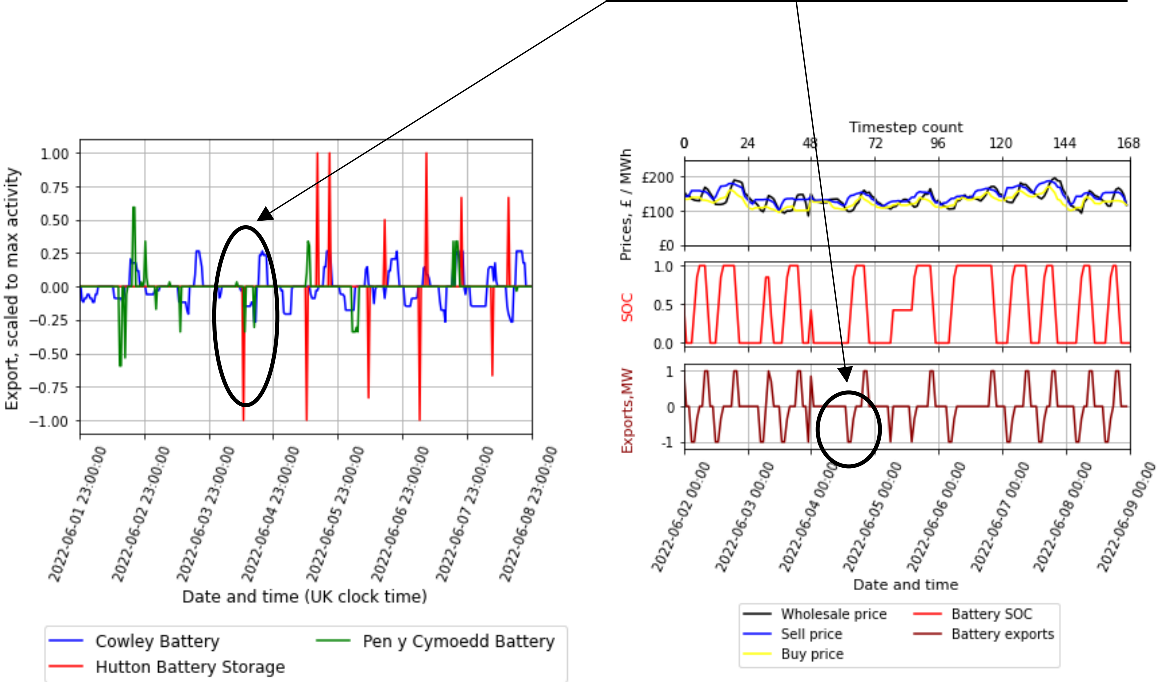


Figure 146 Summer week 2. Real batteries (Cowley, Pen y Cymoedd, and Hutton) FPNs, broadly agreeing with simulation (2hr battery, best cashflow scenario).

Figure 146, showing week 2 of the summer case study period, shows that Cowley, and on some days, Pen y Cymoedd batteries show similar behaviour to the simulation. Most days there are imports at night and midday, and exports in mornings and evenings. Hutton battery has actions that are sometimes similar and sometimes contrary.

Figure 147 and Figure 148 show several batteries for weeks 2 and 5 of the autumn case study period, showing broadly similar patterns of activity to the "two cycles-a-day" simulated.

Figure 149 shows week 3 of the winter case study. Figure 149 (a) shows examples of batteries with broadly similar activity to that simulated, and Figure 149 (c) displays several batteries engaging in additional trades.

Autumn week 2 and autumn week 5

Cowley, Hawkers Hill, Contego, Holes Bay and Hutton batteries' timeseries, compared to simulation.

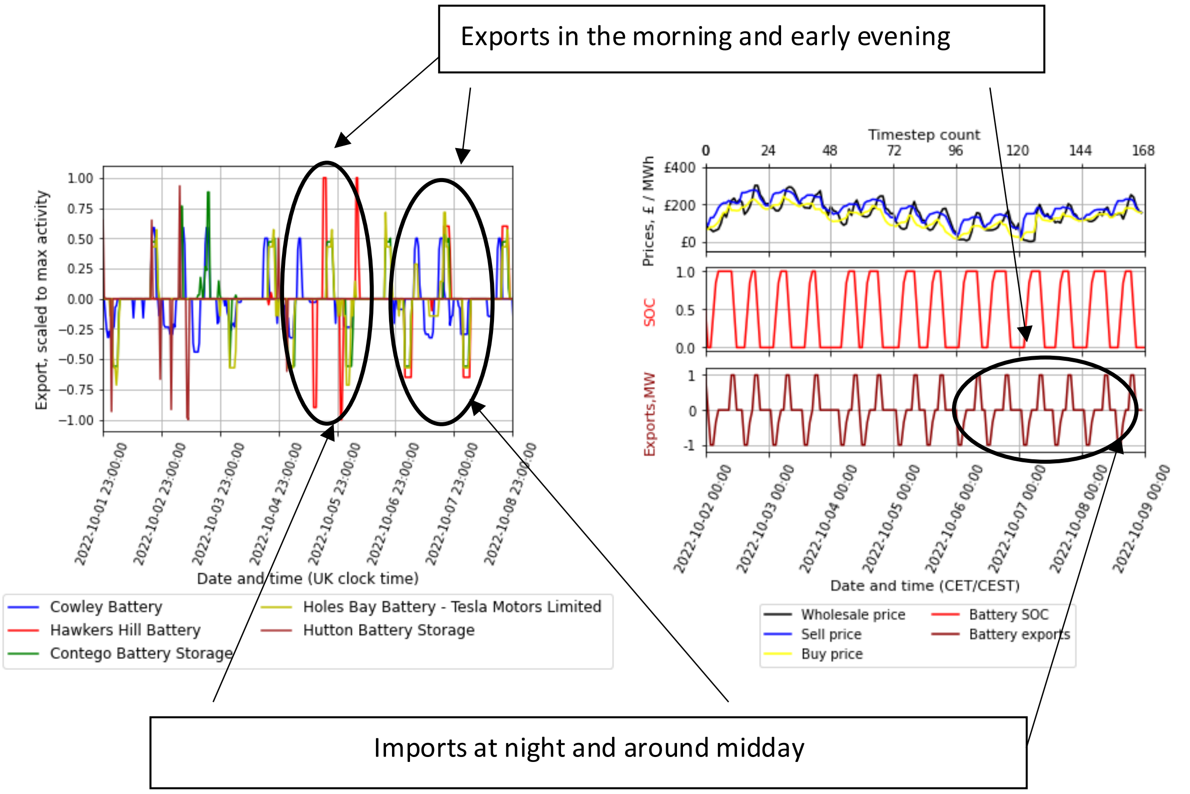


Figure 147 Autumn week 2. 5 batteries' FPNs showing broadly similar behaviour to the simulated 2-cycles / day (2hr battery, best cashflow scenario).

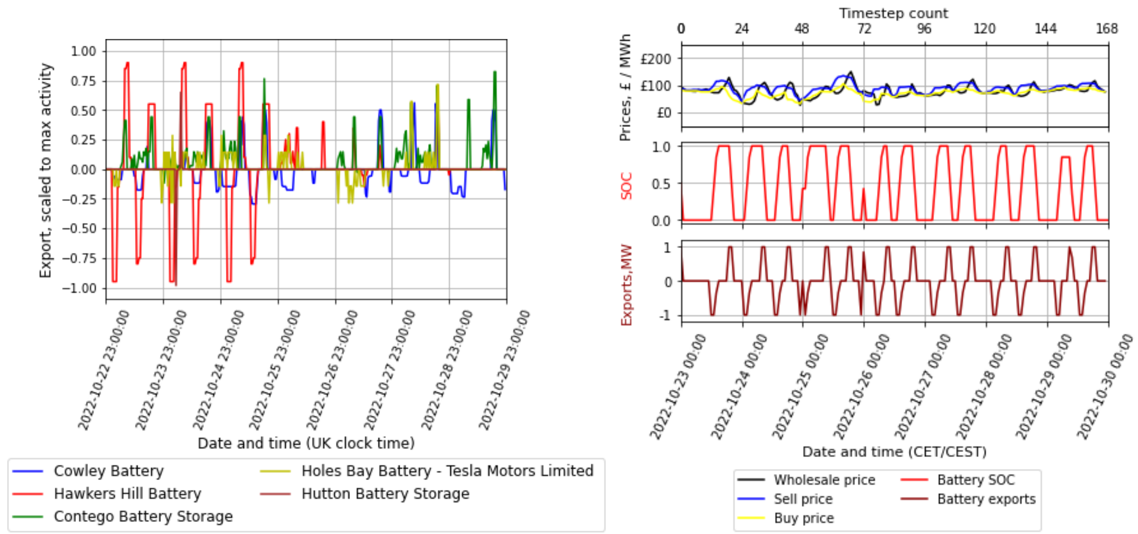
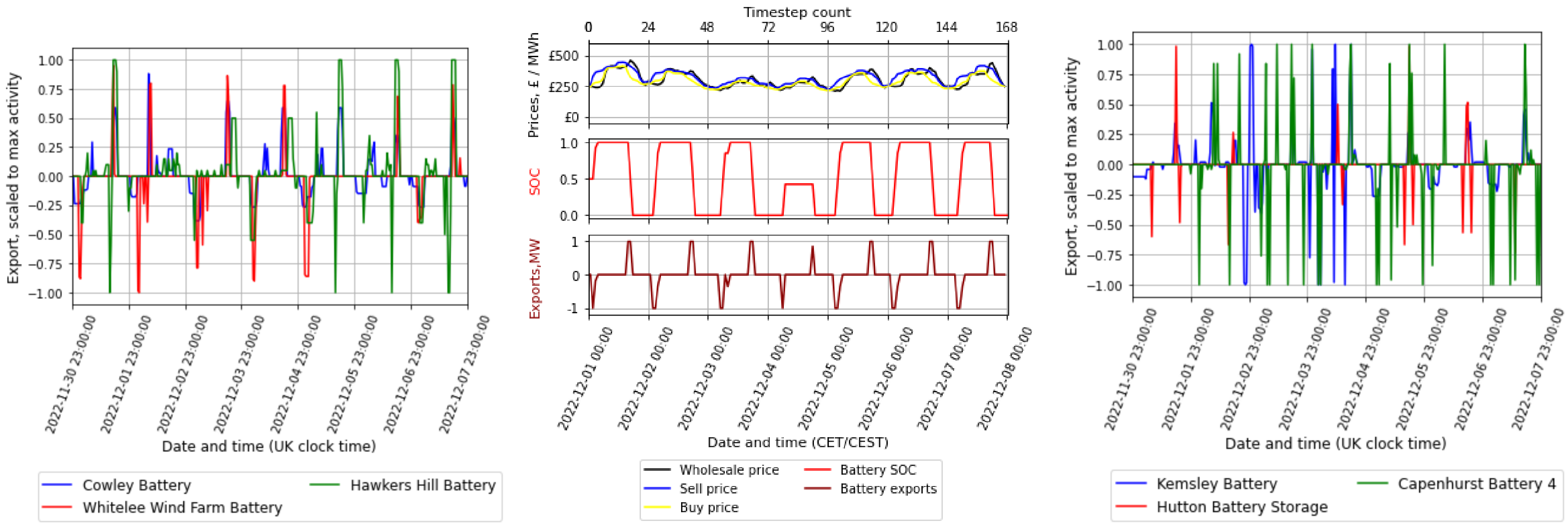


Figure 148 Autumn week 5. The same 5 batteries' FPNs as in Figure 147, but here showing a mixture of broadly similar trades to those simulated (2-hr battery, best cashflow scenario), different trading patterns, and irregular activity

Winter week 3

Cowley, Whitelee and Hawkers Hill batteries, showing similar actions to simulations.

Kemsley, Hutton and Capenhurst 4 batteries showing trades additional to those simulated.



(a) (b) (c)

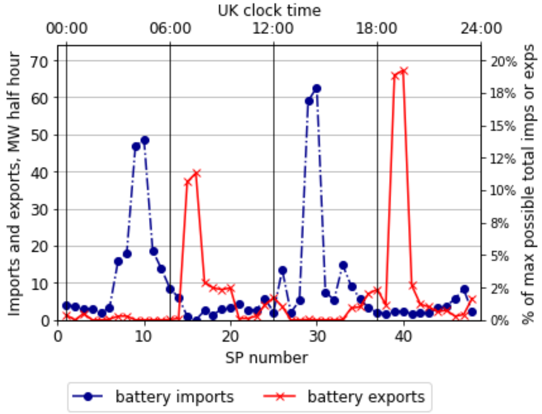
Figure 149 Winter week 3. (a) 3 batteries (Cowley, Whitelee and Hawkers Hill) engaged in broadly similar actions – 1 cycle per day - to those simulated (b). Cowley and Hawkers Hill batteries engaged in an additional daytime trade on several days. (c) shows 3 different batteries (Kemsley, Hutton and Capenhurst 4) engaging in numerous additional trades.

Chapter 4 Annex 6

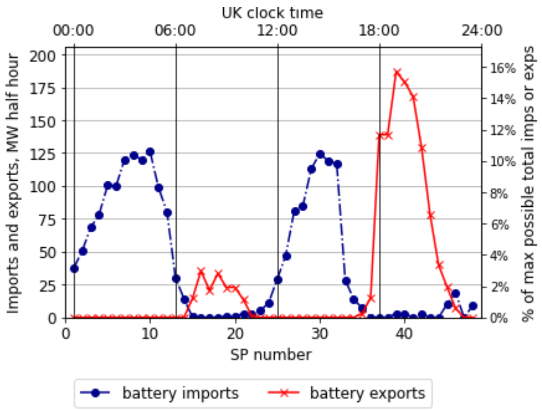
Diurnal activity charts of real batteries, over whole case study periods.

The diurnal patterns of battery activity were investigated, by plotting accumulated activity by Settlement Period (SP) over the whole case study period.

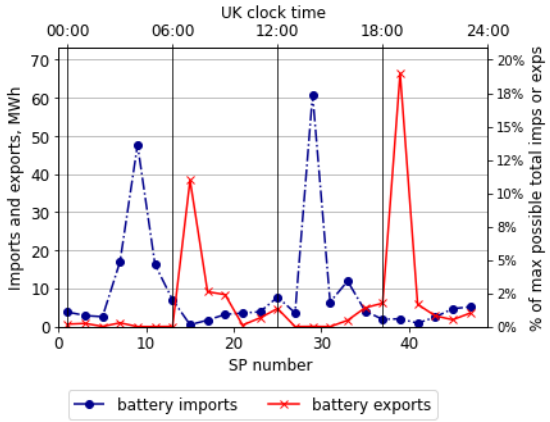
Summer – examples of good agreement between grid batteries and simulation



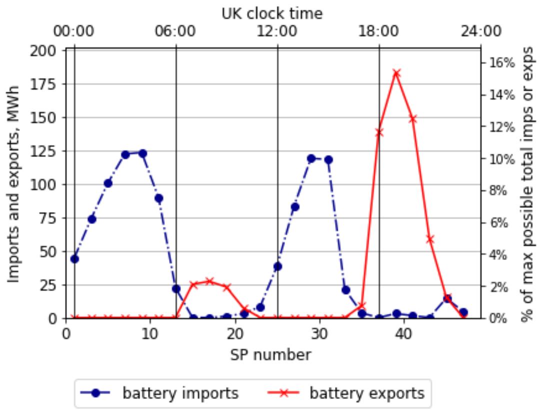
(a) Pen y Cymoedd battery (half-hourly)



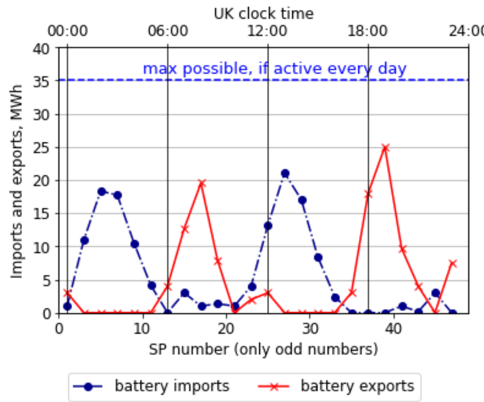
(b) Cowley battery (half-hourly)



(c) Pen y Cymoedd battery (hourly)



(d) Cowley battery (hourly)

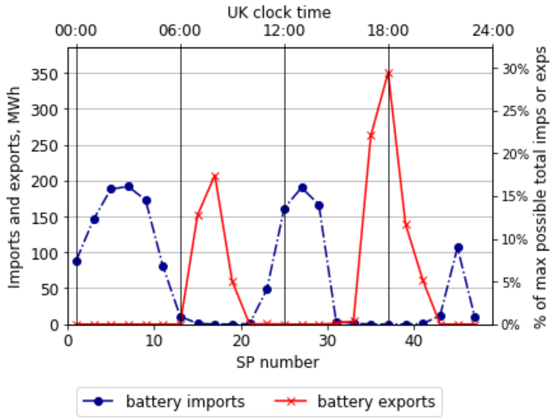


(e) simulated battery (1 MW, 2 hr),

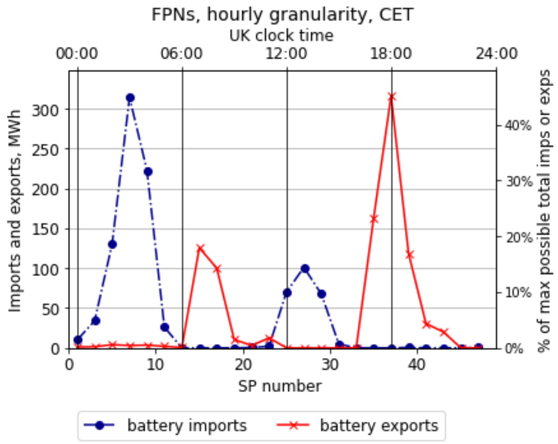
Figure 150 Summer case study, diurnal battery activity. (a) and (b) - aggregate activity by half-hour SP over the case study. (c) and (d) - aggregate activity by SP, smoothed to hourly resolution, for better comparison with simulated activity

(e) simulated aggregate activity by SP of a 1 MW, 2-hr battery, "best cashflow" scenario, hourly timestep.

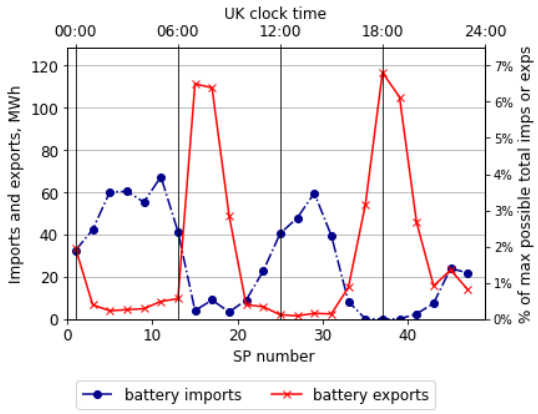
Autumn – examples of good agreement between grid batteries and simulation.



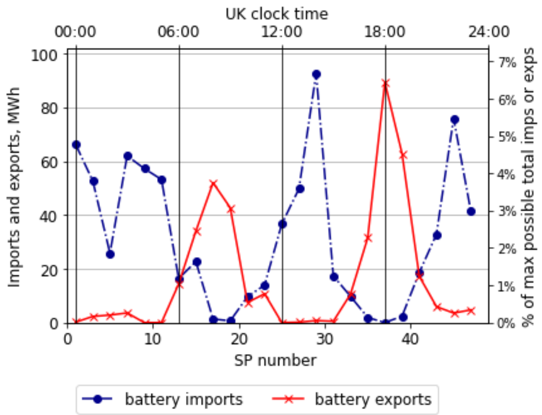
(a) Cowley battery



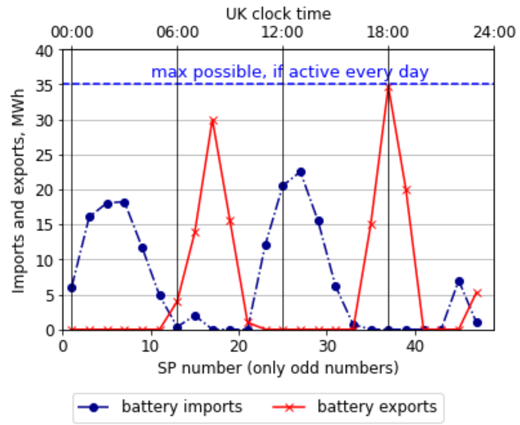
(b) Hawkers Hill battery



(c) Kemsley battery



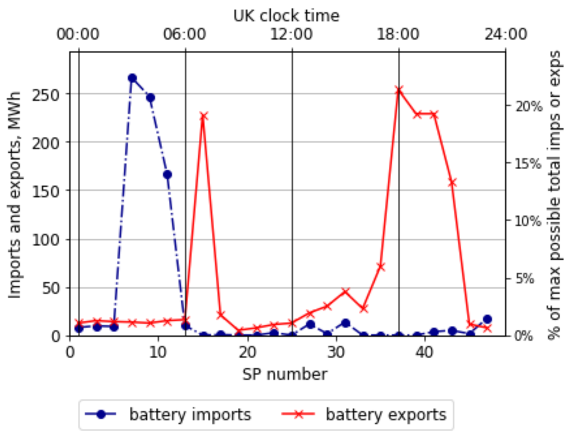
(d) Bloxwich battery



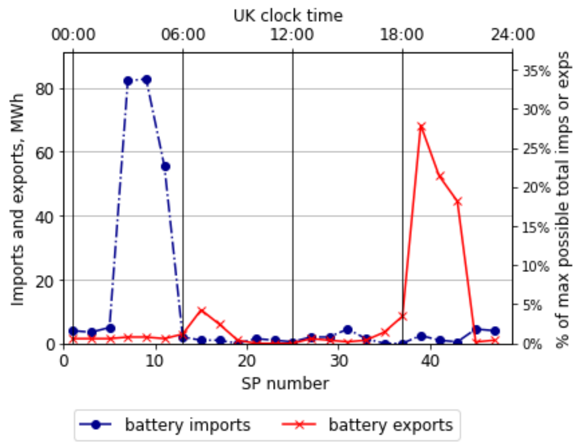
(e) simulated battery (1MW, 2 hr)

Figure 151 Autumn case study, diurnal battery activity. (a) – (d) real batteries, aggregate activity by SP, smoothed to 1-hour resolution for comparison with simulation; (e) simulated battery activity by SP. 1MW, 2 hr battery, "best cashflow" scenario.

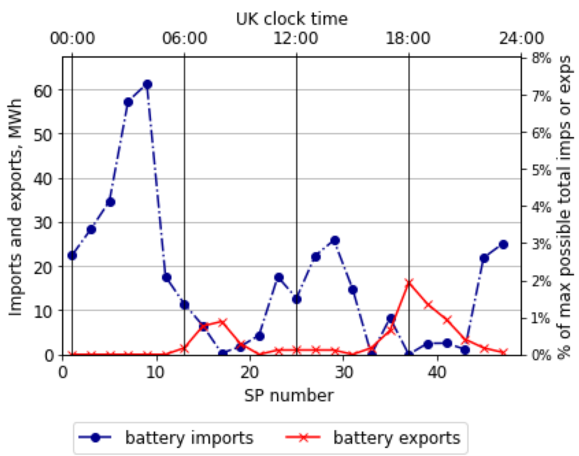
Autumn – examples of grid batteries with some differences in diurnal activity pattern to simulated activity



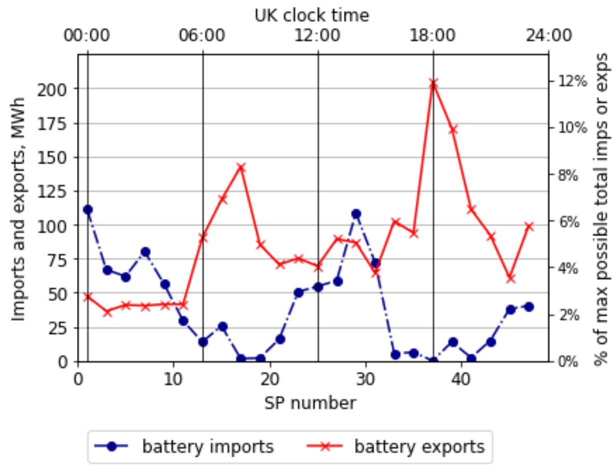
(a) Contego battery



(b) Holes Bay battery



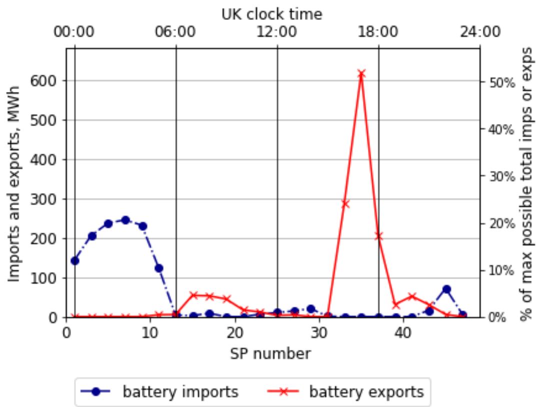
(c) West Burton B 41 battery



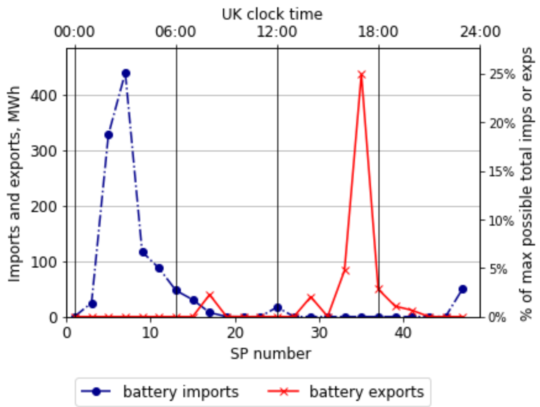
(d) Burwell battery

Figure 152 Autumn case study, diurnal patterns of battery activity. Aggregate battery activity by SP, smoothed to 1-hour resolution. Some example of batteries with slightly different diurnal patterns.

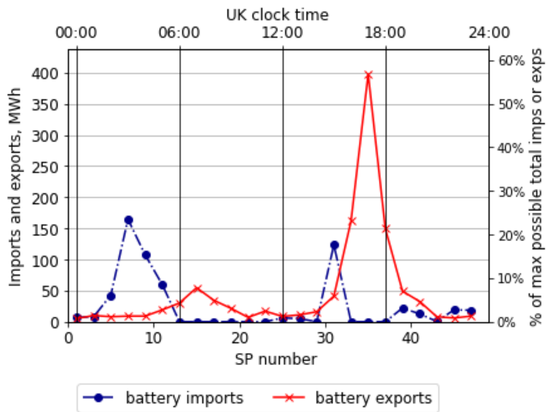
Winter case study – grid batteries with similar diurnal activity pattern to simulated activity



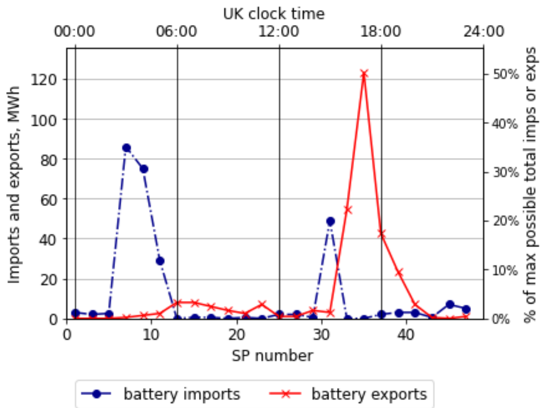
(a) Cowley battery



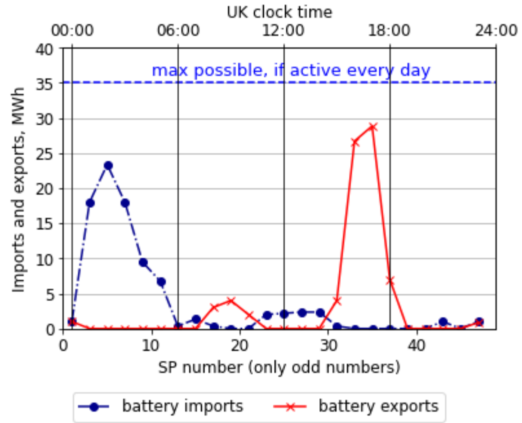
(b) Whitelee Battery



(c) Hawkers Hill battery



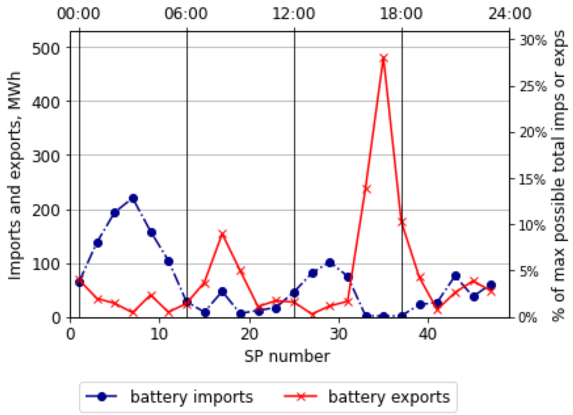
(d) Holes Bay battery



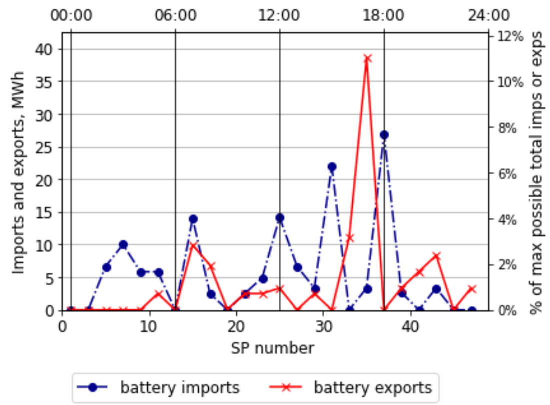
(e) simulated battery (1 MW, 2 hr)

Figure 153 Winter case study. Diurnal patterns of battery activity, batteries with similar behaviour to simulations.
(a) - (d) real batteries, aggregate activity by SP over case study. Activity smoothed to hourly resolution to match simulation.
(e) simulated activity of 1 MW 2-hr battery, "best cashflow" scenario.

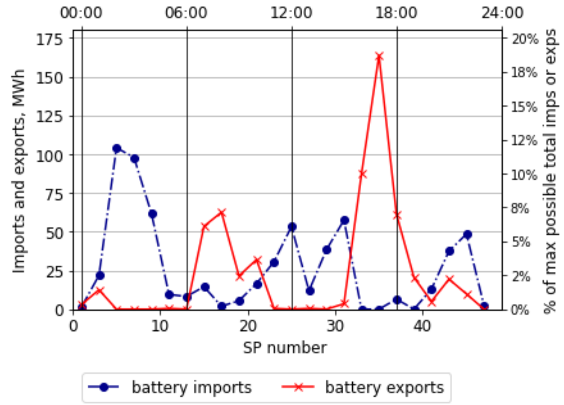
Winter case study – grid batteries some differences in diurnal activity pattern to that simulated



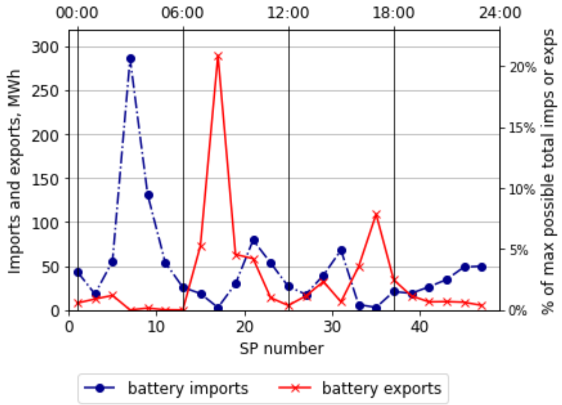
(a) Kemsley



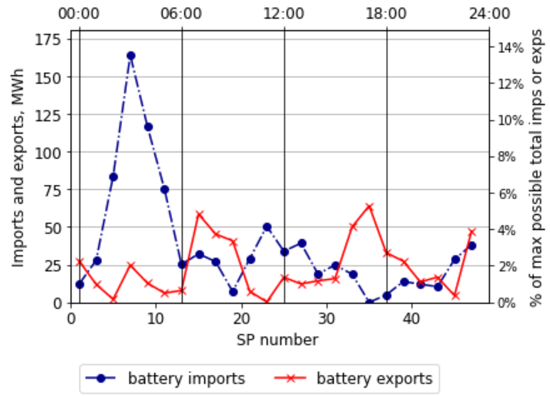
(b) Hutton battery



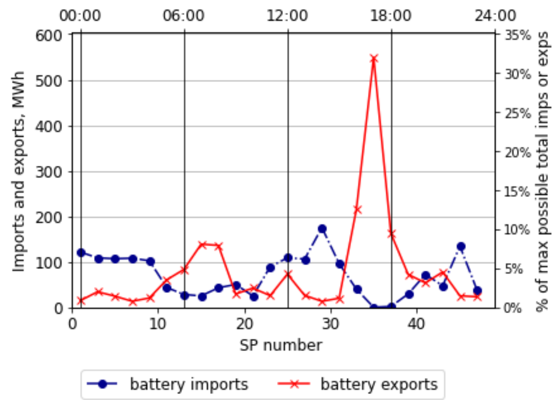
(c) Capenhurst 4 battery



(d) Bloxwich battery



(e) Arbroath battery



(f) Burwell battery

Figure 154 Winter case study. Diurnal patterns of battery activity, showing examples of batteries with additional or different diurnal trading activity to simulation. Battery aggregate activity by SP over the case study, smoothed to 1-hr resolution.

Chapter 4 Annex 7

Comparing features of diurnal activity: all (retained) grid batteries with simulations

The following tables give details of all grid batteries which were active during 2022, and their activity during the 3 case study seasons.

Table 88 and Table 89 are used to decide which real grid-connected batteries should be retained for analysis of diurnal profiles, for comparison with battery simulations. Table 88 lists the individual batteries, whether they are retained for study, and if rejected, on what grounds. Reasons for exclusion were inactivity, or a gross imbalance between FPN MWh of imports and exports.

Table 89 elaborates on the reasons used for inclusion / exclusion, listing the number of MWh of FPN imports and exports during the case study season.

Table 90, Table 91 and Table 92 list all the grid-connected batteries, for the summer, autumn and winter case study seasons, respectively. These tables list which were active, and which retained or excluded from this analysis (as per previous tables) for that case study season. Out of the batteries retained for this analysis, these tables show the various diurnal features of the simulation, and which batteries' actions shared or differed from this feature. At the bottom of the table is the number and percentage of batteries whose actions matched simulations, for each feature.

Table 88 List of real batteries selected for use in validation study, and reason for some batteries' elimination, for each case study season.
(The MWh of FPNs exports and imports are listed in Table 89)

	Battery BMU	Summer			Autumn			Winter		
		Active?	Retain battery in study?	Reason for rejection	Active?	Retain battery?	Reason for rejection	Active?	Retain battery?	Reason for rejection
1	E_ARNKB-1	Yes	Yes		Yes	Yes		Yes	Yes	
2	E_BHOLB-1	Yes	No	Exports >> imports	Yes	Yes		Yes	Yes	
3	E_POTES-1	No	No	Inactive	Yes	Yes		Yes	Yes	
4	E_ROOSB_1	Yes	No	imports only	Yes	No	Imports only	Yes	No	Imports only
5	T_KEMB-1	Yes	No	Imports >> exports	Yes	Yes		Yes	Yes	
6	T_PNYCB-1	Yes	Yes		Yes	No	imports >> exports	Yes	No	imports >> exports
7	T_WBURB-41	Yes	No	Imports only	Yes	No	Imports >> exports	Yes	No	Imports >> exports
8	T_WBURB-43	No	No	Inactive	Yes	No		Yes	No	Imports >> exports
9	T_COWB-1	Yes	Yes		Yes	Yes		Yes	Yes	
10	E_ARNKB-2	Yes	Yes		Yes	Yes		Yes	Yes	
11	E_CONTB-1	Yes	No	Exports >> imports	Yes	Yes		Yes	Yes	
12	T_WHLWB-1	No	No	Inactive	No	No	Inactive	Yes	Yes	
13	E_BURWB-1	Yes	Yes		Yes	Yes		Yes	Yes	
14	E_BARNB-1	No	No	Inactive	No	No	Inactive	No	No	Inactive
15	T_PINFB-1	(yes)	No	Imports only	No	No	Inactive	Yes	Yes	
16	T_PINFB-2	(yes)	No		No	No	Inactive	Yes	Yes	
17	T_PINFB-3	(yes)	No		No	No	Inactive	Yes	Yes	
18	T_PINFB-4	(yes)	No		No	No	Inactive	Yes	Yes	
19	E_ARBRB-1	No	No	Inactive	No	No	Inactive	Yes	Yes	
20	E_HAWKB-1	No	No	Inactive	Yes	Yes		Yes	Yes	
21	E_PILLB-1	No	No	Inactive	No	No	Inactive	Yes	Yes	
22	E_PILLB-2	No	No	Inactive	No	No	Inactive	No	No	Inactive
23	E_SKELB-1	No	No	Inactive	No	No	Inactive	Yes	Yes	
Number of batteries		14	5		13	9		21	17	

Table 89 Individual batteries: volumes of energy import and import during the case study seasons (estimated from FPNs only). A criterion for eliminating some batteries from validation study

	Battery BMU	Summer				Autumn				Winter			
		FPNs	Estimated volumes of FPNs, MWh		Retain? Y/N	FPNs	Estimated volumes of FPNs, MWh		Retain?	FPNs	Estimated volumes FPNs, MWh		Retain?
			Exports	Imports			Exports	Imports			Exports	Imports	
1	E_ARNKB-1	Yes	491	786	Yes	Yes	406	796	Yes	Yes	877	1195	Yes
2	E_BHOLB-1	Yes	253	14	No	Yes	216	265	Yes	Yes	305	277	Yes
3	E_POTES-1	No	0	0	No	Yes	274	467	Yes	Yes	395	541	Yes
4	E_ROOSB_1	Yes	0	308	No	Yes	0	255	No	Yes	0	244	No
5	T_KEMB-1	Yes	35	308	No	Yes	777	684	Yes	Yes	1908	1652	Yes
6	T_PNYCB-1	Yes	162	224	Yes	Yes	7	90	No	Yes	26	106	No
7	T_WBURB-41	Yes	0	330	No	Yes	70	421	No	Yes	4	175	No
8	T_WBURB-43	No	No	No	No	Yes	19	249	No	Yes	19	209	No
9	T_COWB-1	Yes	635	998	Yes	Yes	1239	1581	Yes	Yes	1433	1353	Yes
10	E_ARNKB-2	Yes	113	124	Yes	Yes	36	56	Yes	Yes	101	135	Yes
11	E_CONTB-1	Yes	1407	82	No	Yes	1470	774	Yes	Yes	2075	773	Yes
12	T_WHLWB-1	No	0	0	No	No	0	0	No	Yes	676	1149	Yes
13	E_BURWB-1	Yes	562	575	Yes	Yes	2098	985	Yes	Yes	2076	1842	Yes
14	E_BARNB-1	No	0	0	No	No	0	0	No	No	0	0	No
15	T_PINFB-1	(yes)	0	19	No	No	0	0	No	Yes	598	676	Yes
16	T_PINFB-2	(yes)	0	32	No	No	0	0	No	Yes	647	691	Yes
17	T_PINFB-3	(yes)	0	19	No	No	0	0	No	Yes	595	666	Yes
18	T_PINFB-4	(yes)	0	19	No	No	0	0	No	Yes	578	664	Yes
19	E_ARBRB-1	No	0	0	No	No	0	0	No	Yes	639	973	Yes
20	E_HAWKB-1	No	0	0	No	Yes	915	984	Yes	Yes	1123	605	Yes
21	E_PILLB-1	No	0	0	No	No	0	0	No	Yes	1189	1425	Yes
22	E_PILLB-2	No	0	0	No	No	0	0	No	No	0	0	No
23	E_SKELB-1	No	0	0	No	No	0	0	No	Yes	171	300	Yes

Table 90 Summer case study. Comparison of real batteries' diurnal activity features, with those of the simulation (2-hr batteries, "best cashflow" scenario)

	Battery BMU	**Inclusion**		**Diurnal activity feature**											
		Active? (non-zero FPNs)	Re-tained in study?	**Night-time import**		**Morning export**		**Daytime import**		**Late afternoon / early evening export**		**Other imports**		**Other exports**	
				Indiv. batts	Simul -ation	Indiv. batts	Simul-ation	Indiv. batts	Simul - ation	Indiv. batts	Simul-ation	Indiv. batts	Simul-ation	Indiv. batts	Simul -ation
1	E_ARNKB-1	Yes	Yes	Yes		yes		yes		yes		no		no	
2	E_BHOLB-1	Yes	No												
3	E_POTES-1	No	No												
4	E_ROOSB_1	Yes	No												
5	T_KEMB-1	Yes	No												
6	T_PNYCB-1	Yes	Yes	yes		yes		yes		yes		no		no	
7	T_WBURB-41	Yes	No		Yes		Yes		Yes		Yes		No		No
8	T_WBURB-43	No	No												
9	T_COWB-1	Yes	Yes	yes		yes		yes		yes		no		no	
10	E_ARNKB-2	Yes	Yes	yes		yes		yes		yes		yes		yes	
11	E_CONTB-1	Yes	No	Yes											
12	T_WHLWB-1	No	No	Yes											
13	E_BURWB-1	Yes	Yes	yes		yes		yes		yes		no		yes	
14	E_BARNB-1	No	No												
15	T_PINFB-1	(yes)	No												
16	T_PINFB-2	(yes)	No												
17	T_PINFB-3	(yes)	No												
18	T_PINFB-4	(yes)	No												
19	E_ARBRB-1	No	No												
20	E_HAWKB-1	No	No												
21	E_PILLB-1	No	No												
22	E_PILLB-2	No	No												
23	E_SKELB-1	No	No												
No. and % of individual batteries whose actions match the simulated feature				5 / 5	100%	5 / 5	100%	5 / 5	100%	5 / 5	100%	4 / 5	80%	3 / 5	60%

Table 91 Autumn case study. Comparison of real batteries' diurnal activity features, with those of the simulation (2-hr batteries, "best cashflow" scenario)

	Battery BMU	Inclusion		Diurnal activity feature											
		Active? (non-zero FPNs)	Re-tained in study? Y/N	Night-time import		Morning export		Daytime import		Late afternoon / early evening export		Other imports		Other exports	
				Indiv. batts	Simul -ation	Indiv. batts	Simul-ation	Indiv. batts	Simul - ation	Indiv. batts	Simul-ation	Indiv. batts	Simul-ation	Indiv. batts	Simul -ation
1	E_ARNKB-1	Yes	Yes	Yes		yes		Yes		yes		no		no	
2	E_BHOLB-1	Yes	Yes	Yes		Yes		No		Yes		no		no	
3	E_POTES-1	Yes	Yes	Yes		yes		Yes		yes		yes		yes	
4	E_ROOSB_1	Yes	No												
5	T_KEMB-1	Yes	Yes	Yes		yes		Yes		yes		no		no	
6	T_PNYCB-1	Yes	No												
7	T_WBURB-41	Yes	No		Yes		Yes		Yes		Yes		No		No
8	T_WBURB-43	Yes	No												
9	T_COWB-1	Yes	Yes	yes		yes		Yes		yes		no		no	
10	E_ARNKB-2	Yes	Yes	yes		yes		Yes		yes		no		yes	
11	E_CONTB-1	Yes	Yes	yes		yes		No		yes		no		no	
12	T_WHLWB-1	No	No												
13	E_BURWB-1	Yes	Yes	yes		yes		Yes		yes		no		yes	
14	E_BARNB-1	No	No												
15	T_PINFB-1	No	No												
16	T_PINFB-2	No	No												
17	T_PINFB-3	No	No												
18	T_PINFB-4	No	No												
19	E_ARBRB-1	No	No												
20	E_HAWKB-1	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No	No	No
21	E_PILLB-1	No	No												
22	E_PILLB-2	No	No												
23	E_SKELB-1	No	No												
No. and % of individual batteries whose actions match the simulated feature				9 / 9	100%	9 / 9	100%	7 / 9	78%	9 / 9	100%	8 / 9	89%	6 / 9	67%

Table 92 Winter case study. Comparison of real batteries' diurnal activity features, with those of the simulation (2-hr batteries, "best cashflow" scenario)

	Battery BMU	Inclusion		Diurnal activity feature											
		Active? (non-zero FPNs)	Re-tained in study?	Night-time import		Morning export		Daytime import		Late afternoon / early eve' export		Other imports		Other exports	
				Indiv. batts	Simul -ation	Indiv. batts	Simul-ation	Indiv. batts	Simul -ation	Indiv. batts	Simul-ation	Indiv. batts	Simul-ation	Indiv. batts	Simul -ation
1	E_ARNKB-1	Yes	Yes	Yes		Big pk		Yes		Yes		No		no	
2	E_BHOLB-1	Yes	Yes	Yes		Tiny pk		Yes		Yes		No		No	
3	E_POTES-1	Yes	Yes	Yes		Smll pk		Yes		Yes		Yes		Yes	
4	E_ROOSB_1	Yes	No												
5	T_KEMB-1	Yes	Yes	Yes		Smll pk		Yes		Yes		No		Yes	
6	T_PNYCB-1	Yes	No												
7	T_WBURB-41	Yes	No										No		No
8	T_WBURB-43	Yes	No												
9	T_COWB-1	Yes	Yes	Yes		Smll pk		No		Yes		No		No	
10	E_ARNKB-2	Yes	Yes	Yes		Smll pk		yes		Yes		yes		yes	
11	E_CONTB-1	Yes	Yes	Yes		Tiny pk	Small peak	Yes	Min-imal activity	Yes	Large peak	No		No	
12	T_WHLWB-1	Yes	Yes	Yes	Yes	Tiny pk		No		Yes		No		No	
13	E_BURWB-1	Yes	Yes	Yes		Smll pk		yes		Yes		No		yes	
14	E_BARNB-1	No	No												
15	T_PINFB-1	Yes	Yes	Yes		Small peak		Yes		Yes		No		No	
16	T_PINFB-2	Yes	Yes	Yes				Yes		Yes		No		No	
17	T_PINFB-3	Yes	Yes	Yes				Yes		Yes		No		No	
18	T_PINFB-4	Yes	Yes	Yes				Yes		Yes		No	No	No	No
19	E_ARBRB-1	Yes	Yes	Yes		Equl pk		Yes		Yes		Yes		Yes	
20	E_HAWKB-1	Yes	Yes	Yes		Smll pk		Yes		Yes		No		No	
21	E_PILLB-1	Yes	Yes	Yes		Tiny pk		No		Yes		No		No	
22	E_PILLB-2	No	No												
23	E_SKELB-1	Yes	Yes	Yes		No pk		No		Yes		No	No	No	No
No. & % of individual batteries whose actions match the simulated feature				17/17	100%	15 / 17	88%	4 / 17	24%	17/17	100%	14 /17	82%	12/17	71%

Annexes to Chapter 5
Batteries, wind and transmission network flows: a Scottish case study.

Contents

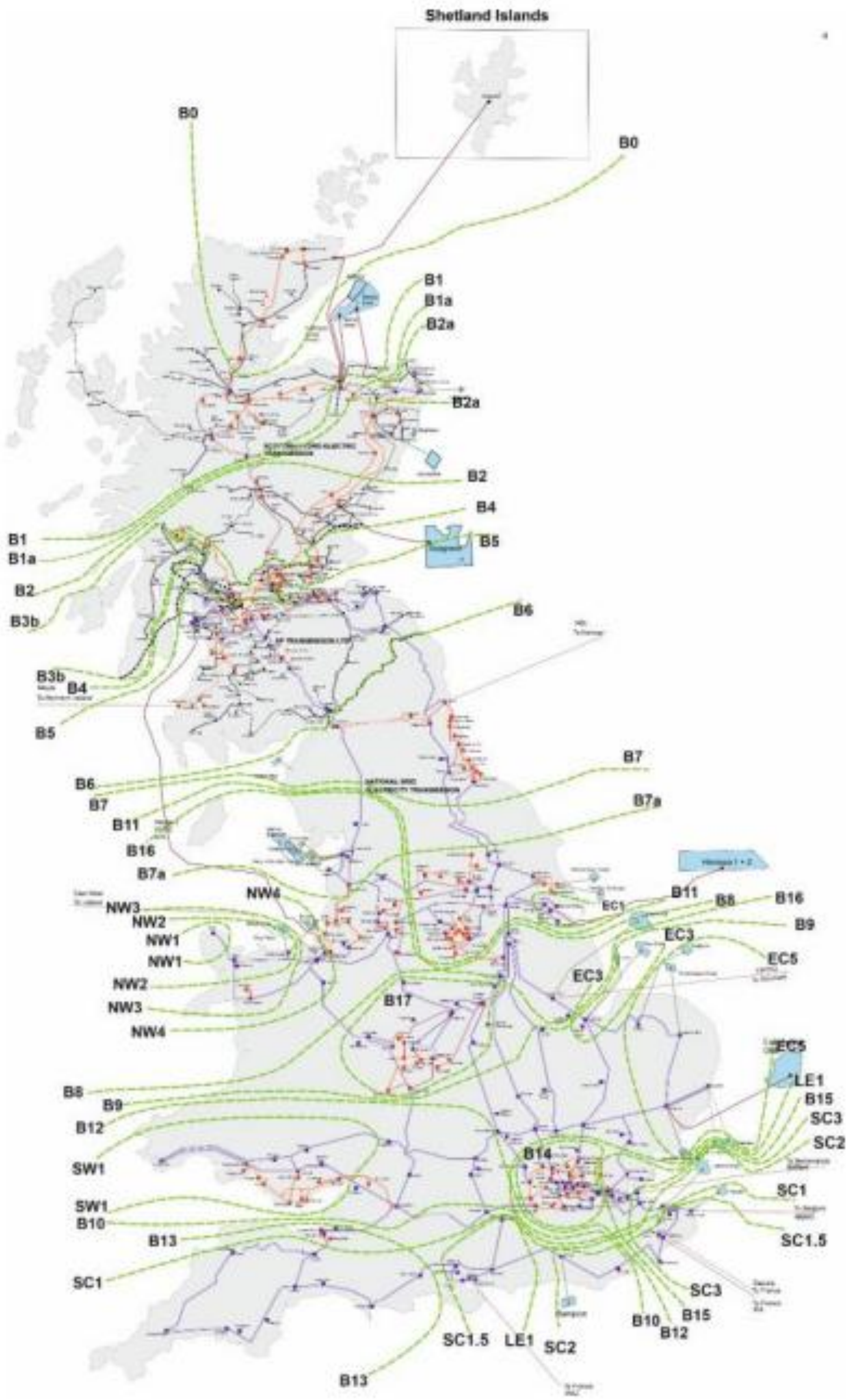
Figures for Annexes to Chapter 5

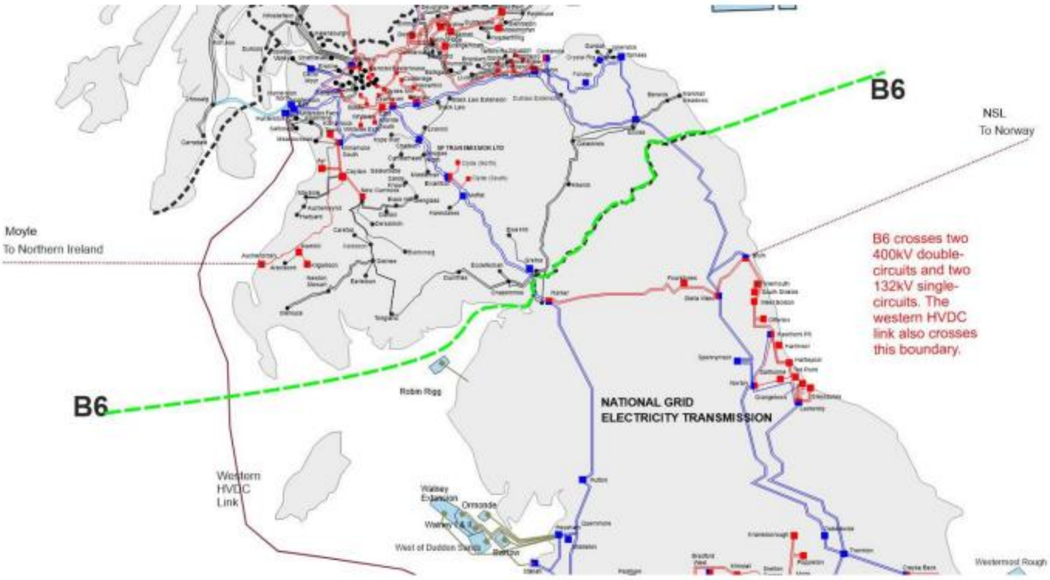
Tables for Annexes to Chapter 5

Chapter 5 Annex 1

Map of GB electricity system and the B6 boundary

The ESO defines "boundaries" across the electricity transmission system. The maps below are reproduced from NESO's Electricity Ten Year Statement (ETYS) 2024 [274].



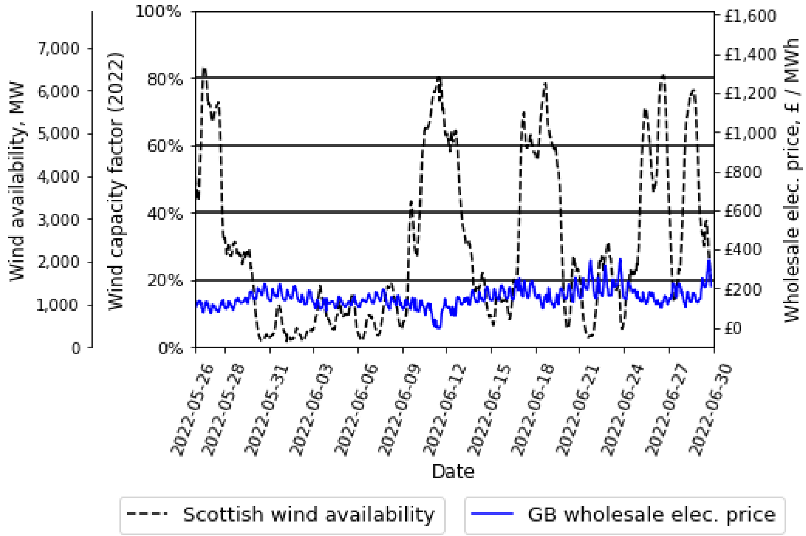


Chapter 5 Annex 2

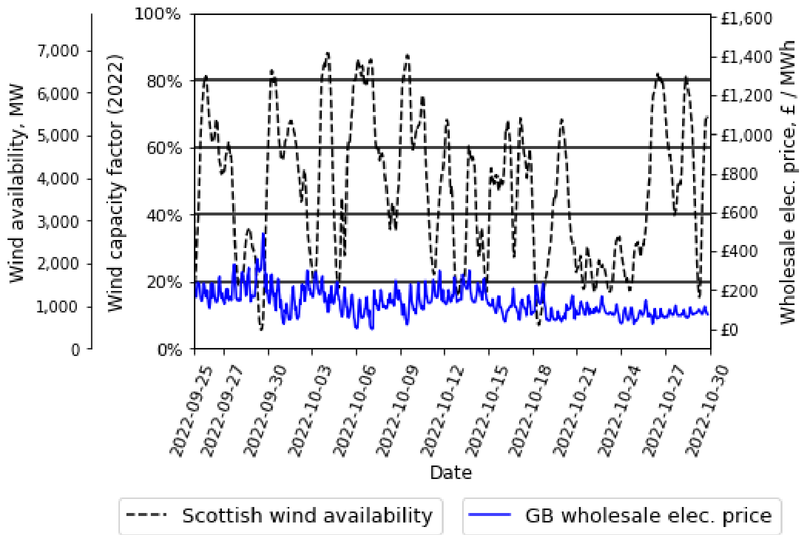
Wholesale electricity price and wind energy

2.1 Wholesale electricity price and Scottish wind availability

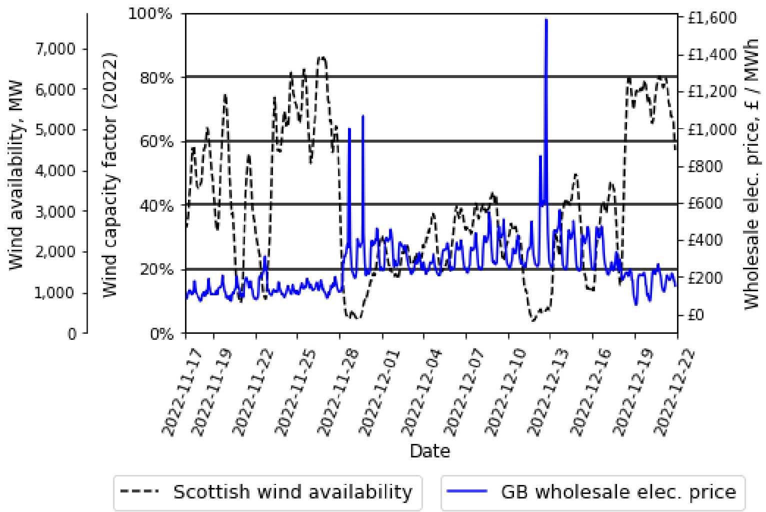
Charts on following page.



(a) Summer case study



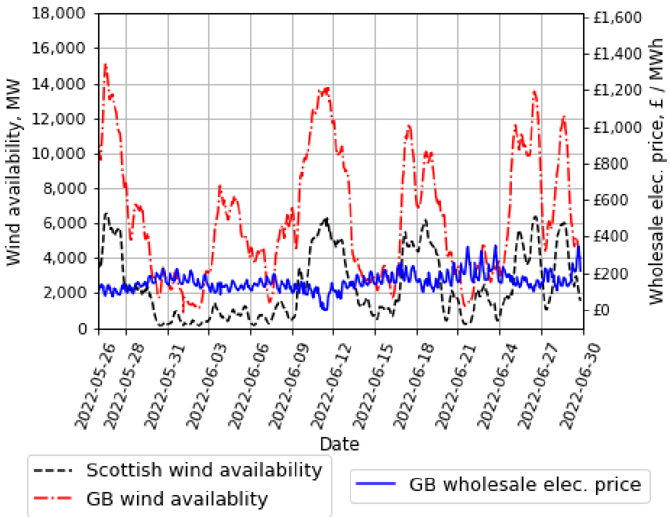
(b) Autumn case study



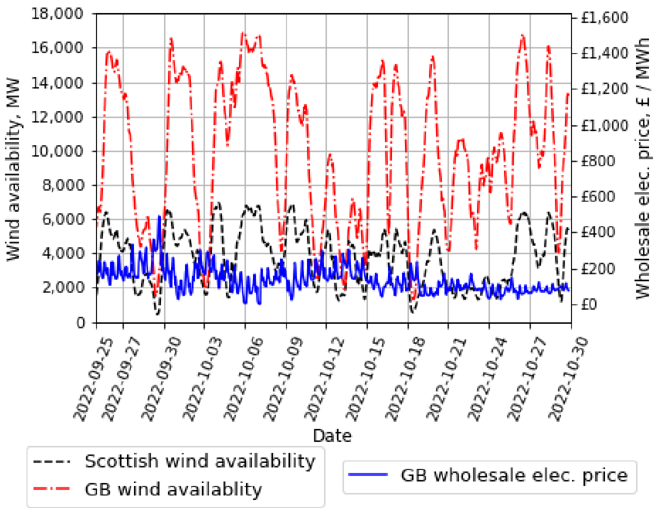
(c) Winter case study

Figure 155 Timeseries Scottish wind availability and capacity factor (hourly) and Wholesale trading price, 2022, Summer, Autumn and Winter case study periods (full scale price axis)

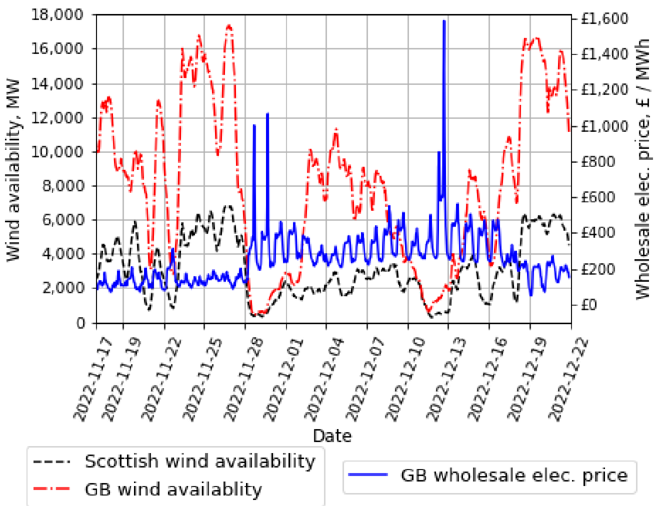
2.2 Wholesale price and GB and Scottish wind availability



(a) Summer case study



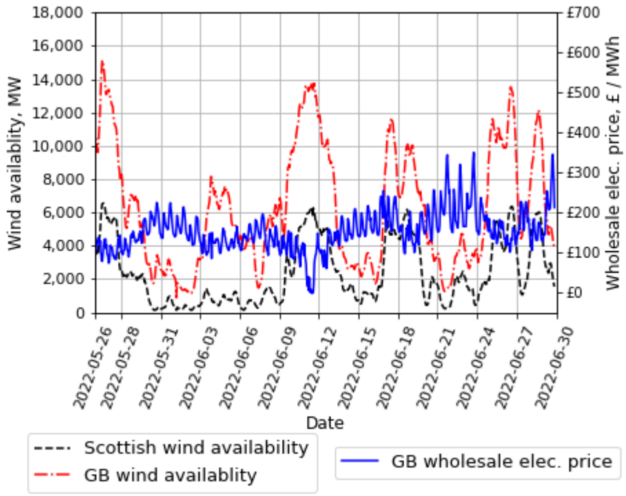
(b) Autumn case study



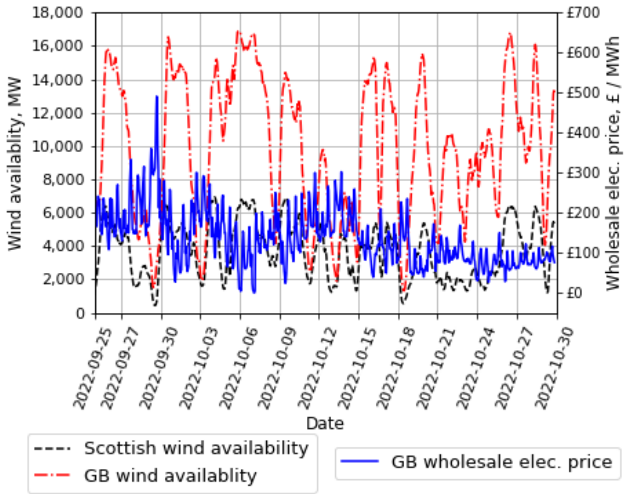
(c) winter case study

Figure 156 Timeseries Scottish and GB wind availability and wholesale electricity trading price, 2022, Summer, Autumn and Winter case study periods (full scale price axis)

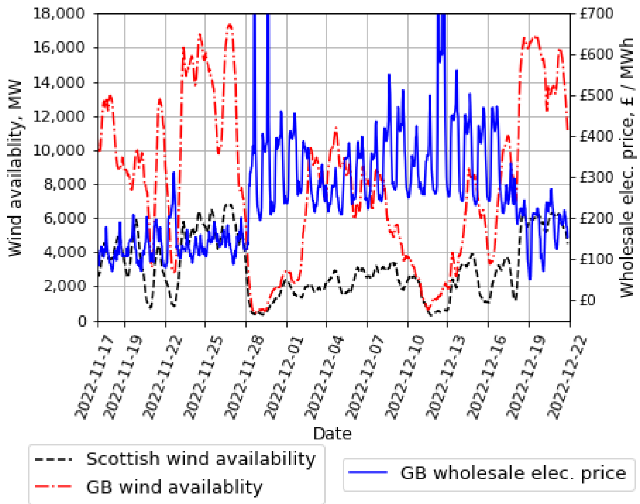
2.3 Wholesale price, and GB and Scottish wind availability



(a) Summer case study



(b) Autumn case study



(c) Winter case study

Figure 157 Timeseries Scottish and GB wind availability, and wholesale electricity trading price, 2022, Summer, Autumn and Winter case study periods (cropped scale price axis)

Chapter 5 Annex 3

Number of hours of wind, and hours of wind curtailment, in each wind quintile, for each season

Table 93 Number and percentage of hours during which wind energy availability falls within each wind energy quintile, for each case study season, and the whole year

Wind availability quintile	Columns A: Number of hours falling in each wind energy quintile, during each season / year				Columns B: Percentage of hours of each case study season / year			
	All year	Summer	Autumn	Winter	All year	Summer	Autumn	Winter
Q1	2,758	399	84	181	31%	48%	10%	22%
Q2	2,394	183	256	317	27%	22%	30%	38%
Q3	1,742	92	234	150	20%	11%	28%	18%
Q4	1,583	155	196	167	18%	18%	23%	20%
Q5	283	11	70	25	3%	1%	8%	3%
Total	8,760	840	840	840	100%	100%	100%	100%

Table 94 Number and percentage of hours during which curtailment of wind energy occurred, within each wind energy quintile, for each case study season, and for the whole year

Wind availability quintile	Columns A: Number of hours during which curtailment of wind generator(s) occurred, falling in each wind energy quintile				Columns B: Percentage of total hours of the case study period (840 hrs) or all year(8760 hrs) during which curtailment occurred				Columns C: Percentage of hours of the wind energy quintile during which curtailment occurred. i.e. hours in Cols A, this table / hours in Table 93, Cols A, applicable Quintile & season			
	All year	Summer	Autumn	Winter	All year	Summer	Autumn	Winter	All year	Summer	Autumn	Winter
Q1	154	25	2	2	2%	3%	0%	0%	6%	6%	2%	1%
Q2	783	75	53	40	9%	9%	6%	5%	33%	41%	21%	13%
Q3	1,327	84	170	82	15%	10%	20%	10%	76%	91%	73%	55%
Q4	1,544	155	195	154	18%	18%	23%	18%	98%	100%	99%	92%
Q5	283	11	70	25	3%	1%	8%	3%	100%	100%	100%	100%
Total	4,091	350	490	303	47%	42%	58%	36%	47%	42%	58%	36%

Chapter 5 Annex 4
Battery activity by wind availability quintile

4.1 Base case battery: 2 hour 85% , "best cashflow" scenarios.

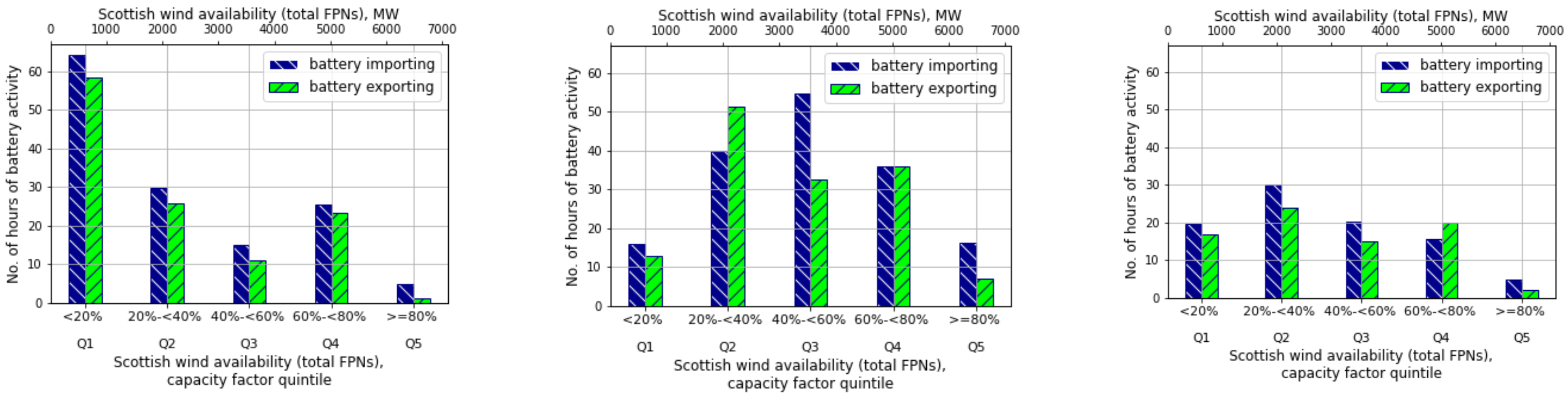
In all cases, the battery trading parameters were "moderate" / 25%, 3hr visibility window, as described in Chapter 4.

Table 95 Aggregate duration of battery activity, and of wind quintile duration, for each wind quintile and season. Base case battery (2hrs, 85% round trip), "best cashflow" scenario

Wind energy availability quintile	Aggregate duration of battery activity, and of wind conditions, hours								
	Summer			Autumn			Winter		
	Battery imports	Battery exports	Total hours	Battery imports	Battery exports	Total hours	Battery imports	Battery exports	Total hours
Q1	64.2	58.4	399	15.9	12.7	84	19.6	16.9	181
Q2	29.7	25.7	183	39.9	51.4	256	29.9	23.9	317
Q3	15.1	11.0	92	54.8	32.6	234	20.1	14.9	150
Q4	25.5	23.3	155	36.0	35.9	196	15.5	19.9	167
Q5	4.7	1.0	11	16.1	6.9	70	4.7	2.0	25
total	139.2	119.4	840	162.8	139.4	840	89.9	77.4	840

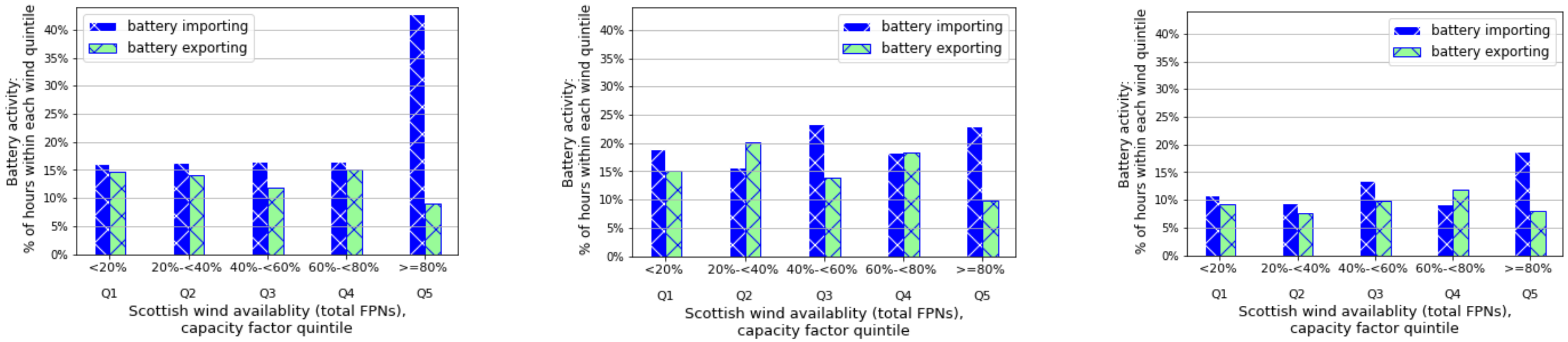
Table 96 Battery activity duration, as a percentage of duration of respective wind energy quintile, for each season. Base case battery (2hrs, 85% round trip), "best cashflow" scenario

Wind energy availability quintile	Proportional duration of battery activity, as a percentage of the duration of wind quintile conditions					
	Summer		Autumn		Winter	
	imports	exports	imports	exports	imports	exports
Q1	16.1%	14.6%	19.0%	15.1%	10.9%	9.3%
Q2	16.2%	14.0%	15.6%	20.1%	9.4%	7.5%
Q3	16.4%	12.0%	23.4%	13.9%	13.4%	9.9%
Q4	16.5%	15.0%	18.4%	18.3%	9.3%	11.9%
Q5	42.8%	9.1%	23.0%	9.8%	18.8%	8.0%



(d) Summer (e) Autumn (f) Winter

Figure 158 Aggregate durations of battery imports and exports during each wind energy availability quintile. Summer, Autumn and Winter case studies. Base case battery (2 hrs, 85% round trip), "best cashflow" scenario[99] for each season



(d) Summer (e) Autumn (f) Winter

Figure 159 Proportional durations of battery imports and exports, i.e. duration of battery activity as a percentage of each respective wind quintile duration. Summer, Autumn and Winter case studies. Base case battery (2 hrs, 85% round trip), "best cashflow" scenario for each season

[99] For base case 2hr 85% round-trip battery, in all cases, "best cashflow" scenario was "moderate" trading strategy, 3 hours visibility window

4.2 Base case battery: 2 hour 85% , scenarios with lower battery cycling

4.2.1 "Second choice / Lower cycling" – cycling approaching 1 cycle per day

Simulations were run with the same battery parameters (2 hour duration, 85% round-trip efficiency), but with different trading parameters, as shown in Table 97 below.

Table 97 Trading parameters for battery simulations: lower cycling scenarios (cycling approaching 1 cycle per day), all seasons

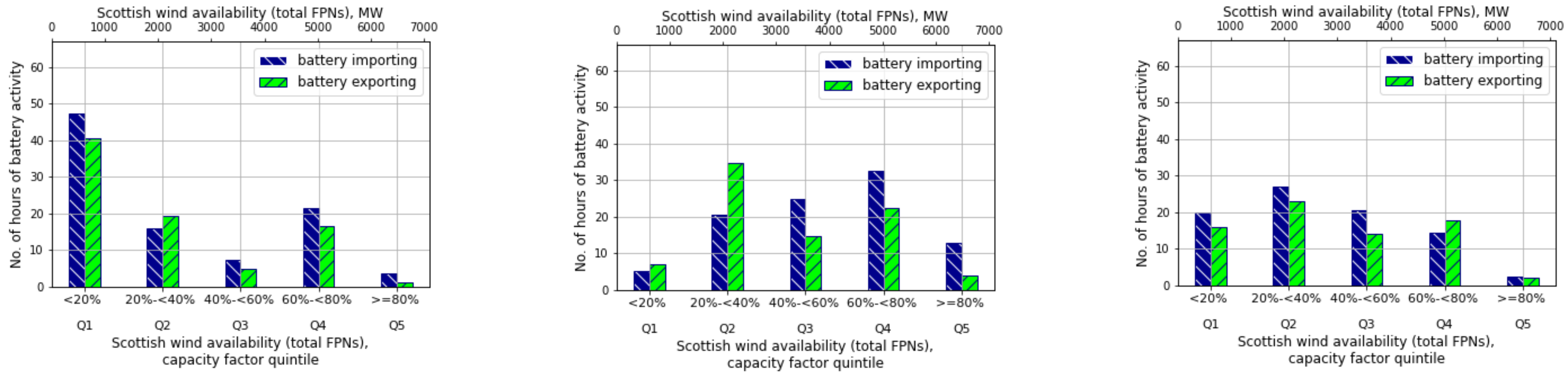
	Summer	Autumn	Winter
Battery trading strategy and visibility window	"best price / 5%", 5hrs	"best price / 5%", 5hrs	"best price / 5%", 4hrs

Table 98 Aggregate duration of battery activity, and of wind quintile duration, for each wind quintile and season. Base case battery (2hrs, 85% round trip), "lower cycling " scenario

	Aggregate duration of battery activity, and of wind conditions, hours								
	Summer			Autumn			Winter		
Wind energy availability quintile	Battery imports	Battery exports	Total hours	Battery imports	Battery exports	Total hours	Battery imports	Battery exports	Total hours
Q1	47.5	40.7	399	5.1	7.0	84	20.0	16.0	181
Q2	15.9	19.4	183	20.6	34.6	256	27.1	23.0	317
Q3	7.4	4.9	92	24.8	14.8	234	20.6	14.0	150
Q4	21.4	16.7	155	32.5	22.3	196	14.5	17.9	167
Q5	3.7	1.0	11	12.9	4.0	70	2.4	2.0	25
total	95.9	82.6	840	96.0	82.6	840	84.5	72.9	840

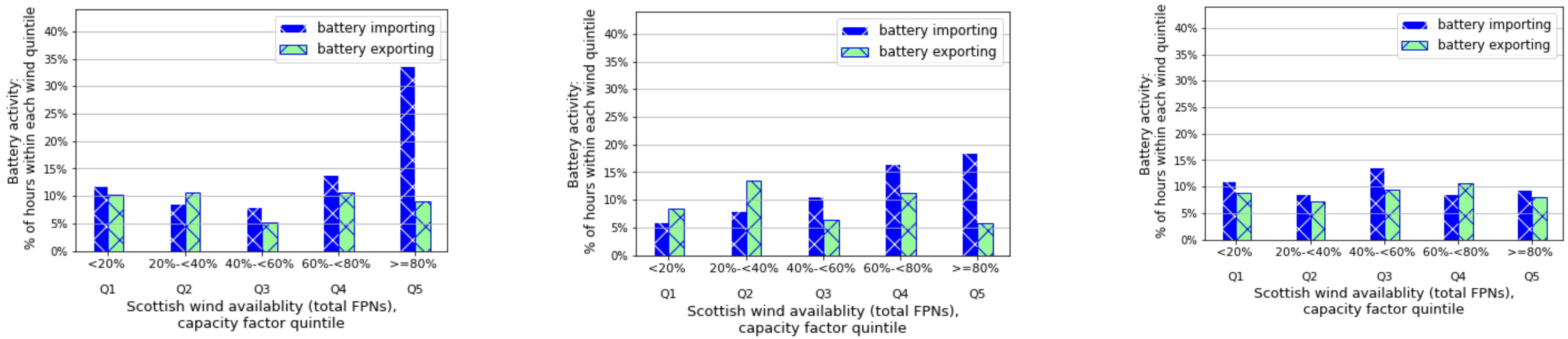
Table 99 Battery activity duration, as a percentage of duration of respective wind energy quintile, for each season. Base case battery (2hrs, 85% round trip), "lower cycling " scenarios

Wind energy availability quintile	Proportional duration of battery activity, as a percentage of the duration of wind quintile conditions					
	Summer		Autumn		Winter	
	imports	exports	imports	exports	imports	exports
Q1	11.9%	10.2%	6.0%	8.3%	11.0%	8.8%
Q2	8.7%	10.6%	8.1%	13.5%	8.5%	7.3%
Q3	8.1%	5.3%	10.6%	6.3%	13.8%	9.3%
Q4	13.8%	10.7%	16.6%	11.4%	8.7%	10.7%
Q5	33.7%	9.1%	18.5%	5.7%	9.4%	8.0%



(a) Summer (b) Autumn (c) Winter

Figure 160 Aggregate durations of battery imports and exports during each wind energy availability quintile (as shown in Table 98). Summer, Autumn and Winter case studies. Base case battery (2 hrs, 85% round trip), "lower cycling" (approaching 1 cycle per day) scenario[100] for each season



(a) Summer (b) Autumn (c) Winter

Figure 161 Proportional durations of battery imports and exports, i.e. duration of battery activity as a percentage of each respective wind quintile duration (as shown in Table 99). Summer, Autumn and Winter case studies. Base case battery (2 hrs, 85% round trip), "lower cycling" (approaching 1 cycle per day) scenario for each season

[100] Battery simulation trading parameters as shown in Table 97.

4.2.2 *“Third choice / lowest cycling – “hard 1 cycle per day average” limit*

The same parameters were run, but with different trading parameters, as shown in Table 100 below

Table 100 Trading parameters for battery simulations: lowest cycling scenarios (hard 1 cycle-per day on average limit), all seasons

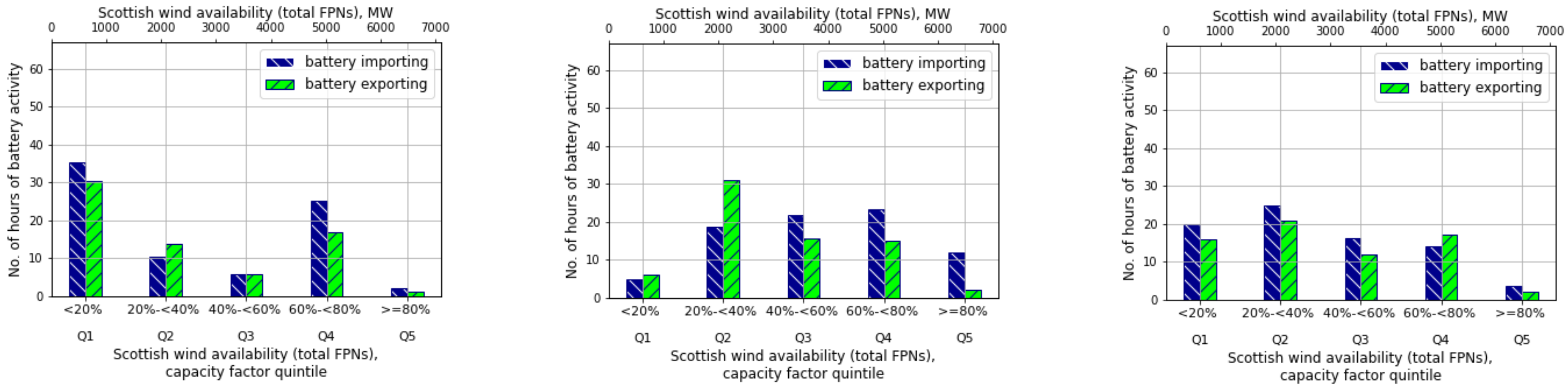
	Summer	Autumn	Winter
Battery trading strategy and visibility window	“10% / good price”, 6hrs	“10% / good price”, 6hrs	“40% / busy”, 3hrs

Table 101 Aggregate duration of battery activity, and of wind quintile duration, for each wind quintile and season. Base case battery (2hrs, 85% round trip), "lowest cycling " scenarios

	Aggregate duration of battery activity, and of wind conditions, hours								
	Summer			Autumn			Winter		
Wind energy availability quintile	Battery imports	Battery exports	Total hours	Battery imports	Battery exports	Total hours	Battery imports	Battery exports	Total hours
Q1	35.2	30.3	399	4.9	6.0	84	20.0	16.0	181
Q2	10.4	13.7	183	18.8	31.0	256	24.9	20.9	317
Q3	5.6	5.9	92	21.8	15.7	234	16.1	12.0	150
Q4	25.1	16.8	155	23.2	14.9	196	13.9	17.0	167
Q5	2.0	1.0	11	11.9	2.0	70	3.7	2.0	25
total	78.4	67.6	840	80.6	69.6	840	78.6	67.9	840

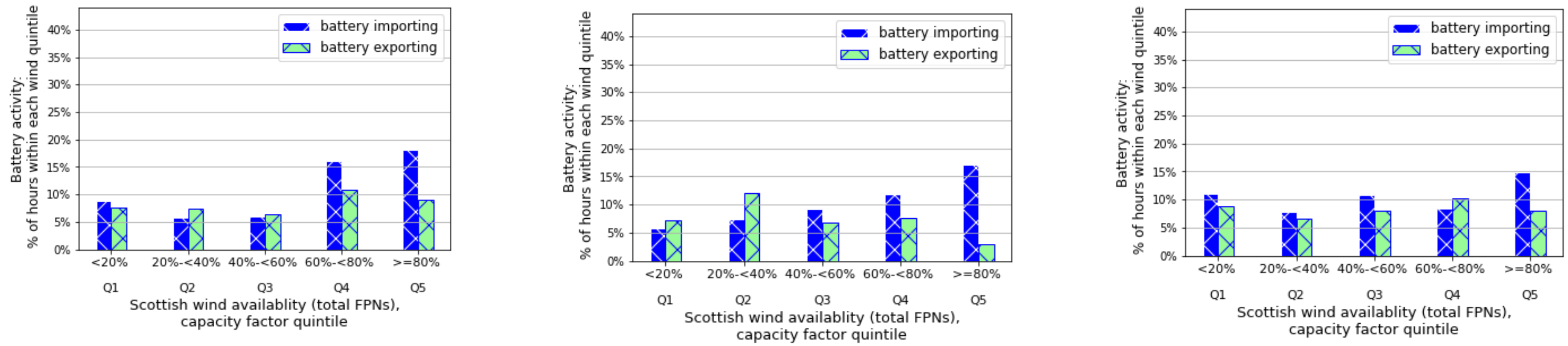
Table 102 Battery activity duration, as a percentage of duration of respective wind energy quintile, for each season. Base case battery (2hrs, 85% round trip), "lowest cycling" scenarios

Wind energy availability quintile	Proportional duration of battery activity, as a percentage of the duration of wind quintile conditions					
	Summer		Autumn		Winter	
	imports	exports	imports	exports	imports	exports
Q1	8.8%	7.6%	5.8%	7.1%	11.0%	8.8%
Q2	5.7%	7.5%	7.4%	12.1%	7.8%	6.6%
Q3	6.1%	6.4%	9.3%	6.7%	10.7%	8.0%
Q4	16.2%	10.8%	11.8%	7.6%	8.3%	10.2%
Q5	18.2%	9.1%	17.1%	2.9%	14.8%	8.0%



(a) Summer (b) Autumn (c) Winter

Figure 162 Aggregate durations of battery imports and exports during each wind energy availability quintile (tabulated in Table 101). Summer, Autumn and Winter case studies. Base case battery (2 hrs, 85% round trip), "lowest cycling" (hard 1-cycle-per-day limit) scenario[101] for each season



(a) Summer (b) Autumn (c) Winter

Figure 163 Proportional durations of battery imports and exports, i.e. duration of battery activity as a percentage of each respective wind quintile duration (tabulated in Table 102). Summer, Autumn and Winter case studies. Base case battery (2 hrs, 85% round trip), "lowest cycling" (hard 1-cycle-per-day limit) scenario for each season

[101] Battery simulation trading parameters as shown Table 100.

Annex 4.3 Batteries of different duration

4.3.1 1-hour battery (85% round trip efficiency), best cashflow scenario

Table 103 Trading parameters for battery simulations: 1-hr 85% round-trip battery, best cashflow scenarios, all seasons

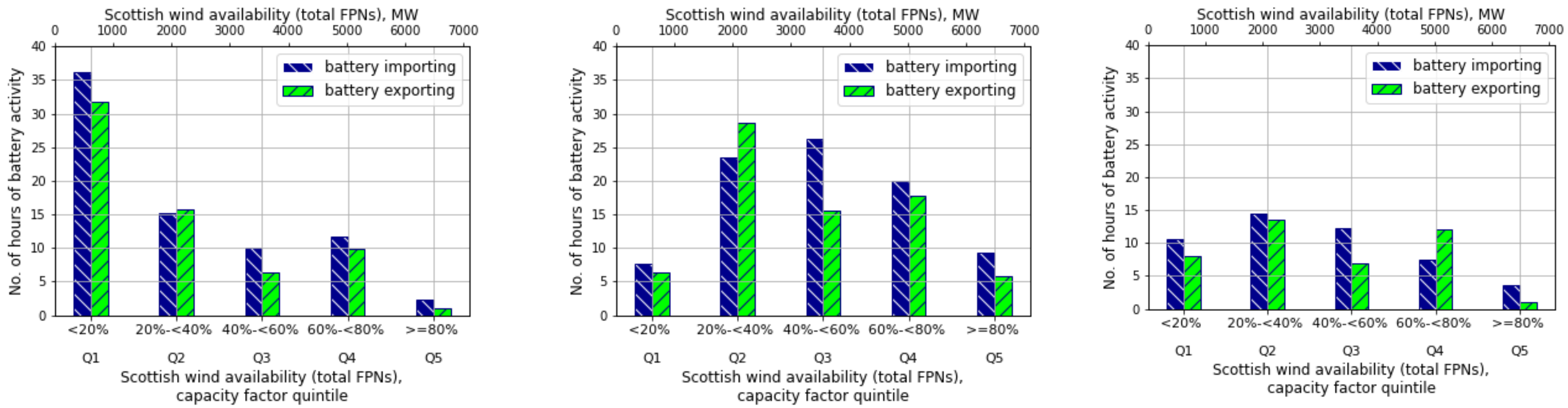
	Summer	Autumn	Winter
Battery trading strategy and visibility window	“5% / best price”, 3hrs	“10% / good price”, 2hrs	“5% / best price”, 3hrs

Table 104 Aggregate duration of battery activity, and of wind quintile duration, for each wind quintile and season. 1-hour battery, 85% round trip, "best cashflow" scenarios

	Aggregate duration of battery activity, and of wind conditions, hours								
	Summer			Autumn			Winter		
Wind energy availability quintile	Battery imports	Battery exports	Total hours	Battery imports	Battery exports	Total hours	Battery imports	Battery exports	Total hours
Q1	36.1	31.7	399	7.7	6.4	84	10.6	8.0	181
Q2	15.1	15.7	183	23.5	28.6	256	14.5	13.5	317
Q3	10.1	6.4	92	26.2	15.6	234	12.2	7.0	150
Q4	11.8	9.9	155	20.0	17.9	196	7.4	12.0	167
Q5	2.4	1.0	11	9.2	5.9	70	3.5	1.0	25
total	75.4	64.6	840	86.6	74.2	840	48.2	41.5	840

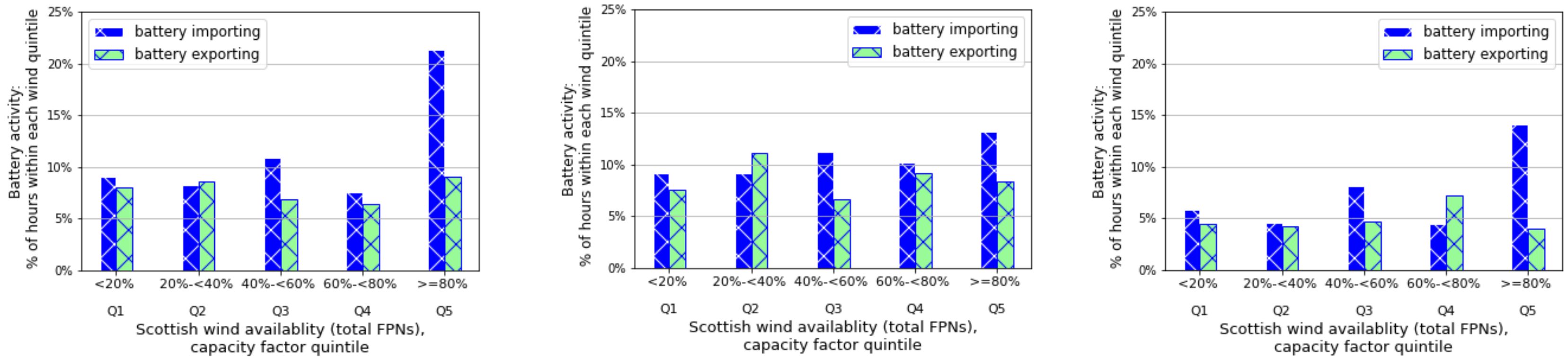
Table 105 Battery activity duration, as a percentage of duration of respective wind energy quintile, for each season. 1-hour battery, 85% round trip, "best cashflow" scenarios

Wind energy availability quintile	Proportional duration of battery activity, as a percentage of the duration of wind quintile conditions					
	Summer		Autumn		Winter	
	imports	exports	imports	exports	imports	exports
Q1	9.1%	7.9%	9.2%	7.6%	5.8%	4.4%
Q2	8.3%	8.6%	9.2%	11.2%	4.6%	4.3%
Q3	10.9%	6.9%	11.2%	6.6%	8.2%	4.7%
Q4	7.6%	6.4%	10.2%	9.1%	4.4%	7.2%
Q5	21.4%	9.1%	13.2%	8.4%	14.1%	4.0%



(a) Summer (b) Autumn (c) Winter

Figure 164 Aggregate durations of battery imports and exports during each wind energy availability quintile (as tabulated in Table 104). Summer, Autumn and Winter case studies. 1-hour battery, 85% round trip efficiency, "best cashflow" scenario[102] for each season



(a) Summer (b) Autumn (c) Winter

Figure 165 Proportional aggregate durations of battery imports and exports, i.e. duration of battery activity as a percentage of each respective wind quintile duration (as tabulated in Table 105). Summer, Autumn and Winter case studies. Battery 1 hr, 85% round trip, "best cashflow" scenario for each season

[102] Battery simulation trading parameters tabulated in Table 103.

4.3.2 4-hour battery (85% round trip efficiency), best cashflow scenario

Table 106 Trading parameters for battery simulations: 4-hour 85% round-trip battery, best cashflow scenarios, all seasons

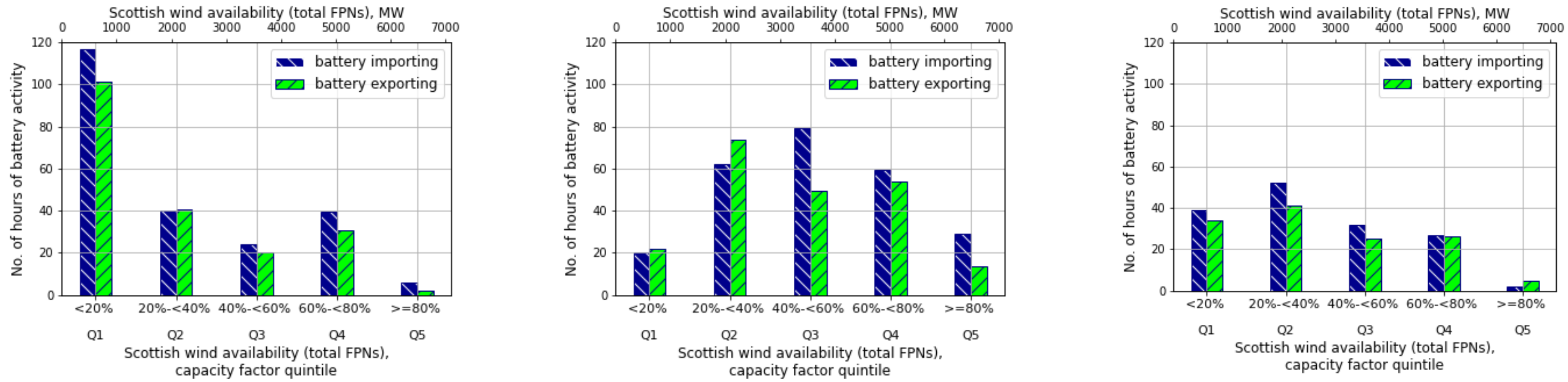
	Summer	Autumn	Winter
Battery trading strategy and visibility window	“moderate / 25%”, 4 hours	“busy / 40%”, 4 hours	“busy / 40%”, 4 hours

Table 107 Aggregate duration of battery activity, and of wind quintile duration, for each wind quintile and season. 4-hour battery, 85% round trip, "best cashflow" scenarios

	Aggregate duration of battery activity, and of wind conditions, hours								
	Summer			Autumn			Winter		
Wind energy availability quintile	Battery imports	Battery exports	Total hours	Battery imports	Battery exports	Total hours	Battery imports	Battery exports	Total hours
Q1	117.0	101.5	399	20.5	22.0	84	38.8	34.0	181
Q2	39.9	40.6	183	61.9	73.6	256	52.1	41.1	317
Q3	24.3	20.0	92	79.1	49.3	234	31.8	25.0	150
Q4	39.6	30.8	155	59.3	54.0	196	26.9	26.0	167
Q5	6.0	2.0	11	28.9	13.4	70	2.2	5.0	25
total	226.8	194.8	840	249.6	212.2	840	151.9	131.1	840

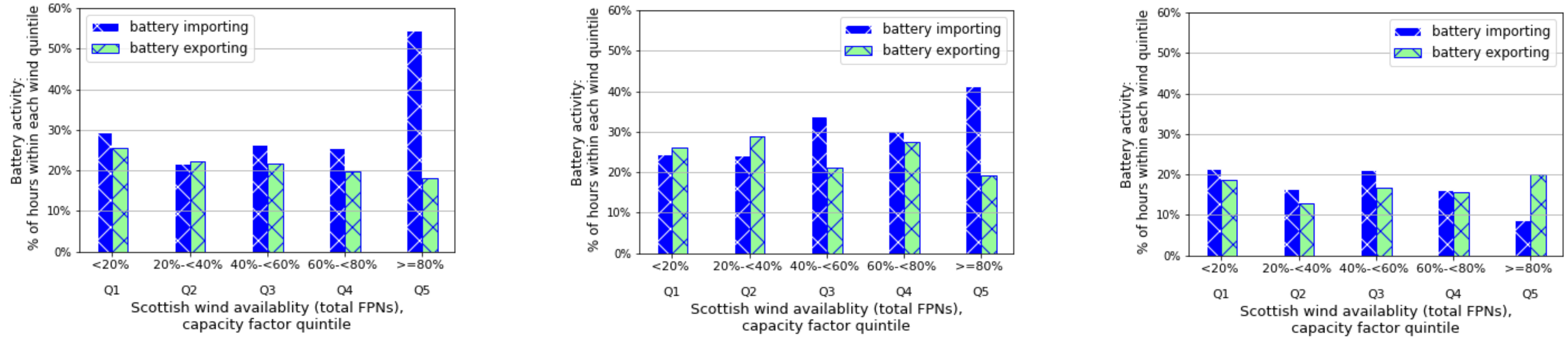
Table 108 Battery activity duration, as a percentage of duration of respective wind energy quintile, for each season. 4-hour battery, 85% round trip, "best cashflow" scenarios

Wind energy availability quintile	Proportional duration of battery activity, as a percentage of the duration of wind quintile conditions					
	Summer		Autumn		Winter	
	imports	exports	imports	exports	imports	exports
Q1	29.3%	25.4%	24.4%	26.2%	21.4%	18.8%
Q2	21.8%	22.2%	24.2%	28.7%	16.4%	13.0%
Q3	26.4%	21.7%	33.8%	21.0%	21.2%	16.7%
Q4	25.6%	19.8%	30.3%	27.5%	16.1%	15.6%
Q5	54.5%	18.2%	41.3%	19.1%	8.7%	20.0%



(a) Summer (b) Autumn (c) Winter

Figure 166 Aggregate durations of battery imports and exports during each wind energy availability quintile, as tabulated in Table 107. Summer, Autumn and Winter case studies. 4-hour battery, 85% round trip efficiency, "best cashflow" scenario[103] for each season



(a) Summer (b) Autumn (c) Winter

Figure 167 Proportional durations of battery imports and exports, i.e. duration of battery activity as a percentage of each respective wind quintile duration, as tabulated in Table 108. Summer, Autumn and Winter case studies. Battery 4 hrs, 85% round trip, "best cashflow" scenario for each season

[103] Battery simulation trading scenarios as shown in Table 106.

4.3.3 12-hour battery (85% round trip efficiency), best cashflow scenario

Table 109 Trading parameters for battery simulations: 12-hour 85% round-trip battery, best cashflow scenarios, all seasons

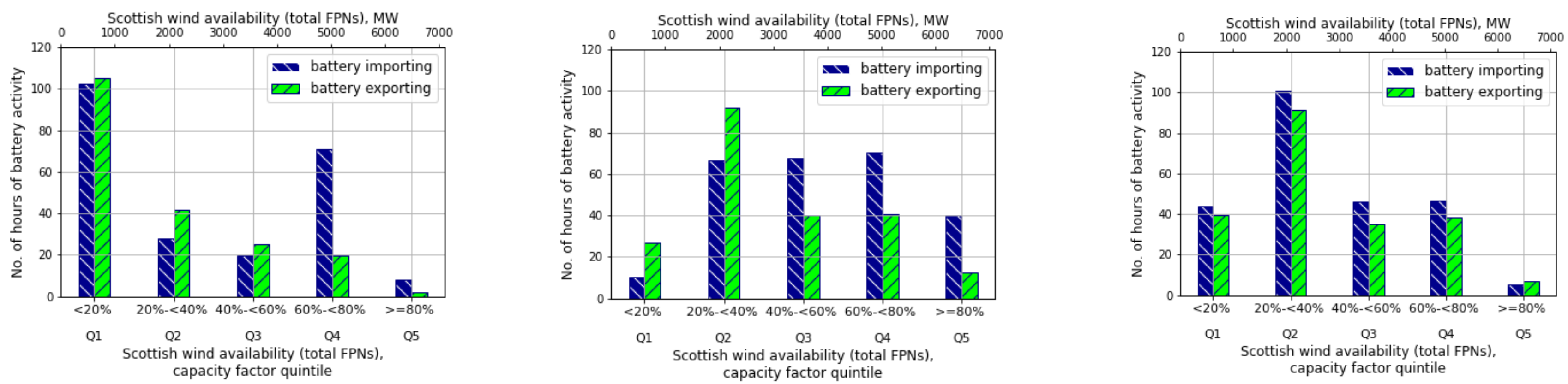
	Summer	Autumn	Winter
Battery trading strategy and visibility window	“busy / 40%”, 10 hrs	“busy / 40%”, 10 hrs	“busy / 40%”, 9 hrs

Table 110 Aggregate duration of battery activity, and of wind quintile duration, for each wind quintile and season. 12-hour battery, 85% round trip, “best cashflow” scenarios

	Aggregate duration of battery activity, and of wind conditions, hours								
	Summer			Autumn			Winter		
Wind energy availability quintile	Battery imports	Battery exports	Total hours	Battery imports	Battery exports	Total hours	Battery imports	Battery exports	Total hours
Q1	102.6	105.0	399	10.1	27.0	84	43.8	39.7	181
Q2	28.0	41.5	183	66.5	92.1	256	100.9	91.6	317
Q3	19.8	25.1	92	67.8	40.2	234	45.9	35.2	150
Q4	71.1	19.7	155	70.4	40.8	196	46.5	38.6	167
Q5	8.0	2.0	11	39.9	12.4	70	5.2	7.0	25
total	229.5	193.1	840	254.7	212.5	840	242.3	212.0	840

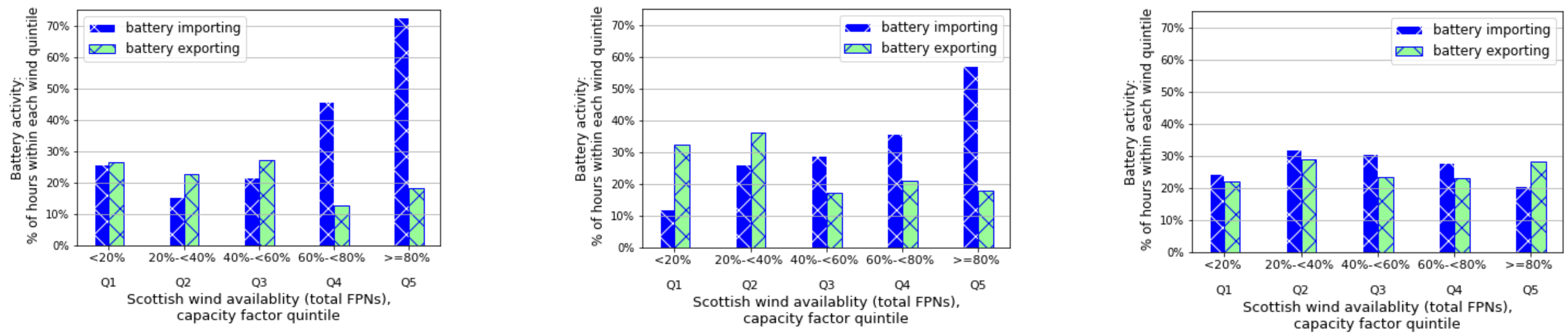
Table 111 Battery activity duration, as a percentage of duration of respective wind energy quintile, for each season. 12-hour battery, 85% round trip, “best cashflow” scenarios

Wind energy availability quintile	Proportional duration of battery activity, as a percentage of the duration of wind quintile conditions					
	Summer		Autumn		Winter	
	imports	exports	imports	exports	imports	exports
Q1	25.7%	26.3%	12.0%	32.1%	24.2%	21.9%
Q2	15.3%	22.7%	26.0%	36.0%	31.8%	28.9%
Q3	21.5%	27.2%	29.0%	17.2%	30.6%	23.4%
Q4	45.9%	12.7%	35.9%	20.8%	27.8%	23.1%
Q5	72.7%	18.2%	57.1%	17.7%	20.7%	28.0%



(a) Summer (b) Autumn (c) Winter

Figure 168 Aggregate durations of battery imports and exports during each wind energy availability quintile, (tabulated in Table 110). Summer, Autumn and Winter case studies. 12-hour battery, 85% round trip efficiency, “best cashflow” scenario[104] for each season



(a) Summer (b) Autumn (c) Winter

Figure 169 Proportional durations of battery imports and exports, i.e. duration of battery activity as a percentage of each respective wind quintile duration (tabulated in Table 111). Summer, Autumn and Winter case studies. Battery 12 hrs, 85% round trip, “best cashflow” scenario for each season

[104] Battery simulation trading parameters are shown in Table 109.

4.3.4 "Flow battery": 12-hour battery (70% round trip efficiency), best cashflow scenario

Table 112 Trading parameters for battery simulations: "flow battery": 12-hour 70% round-trip battery, best cashflow scenarios, all seasons

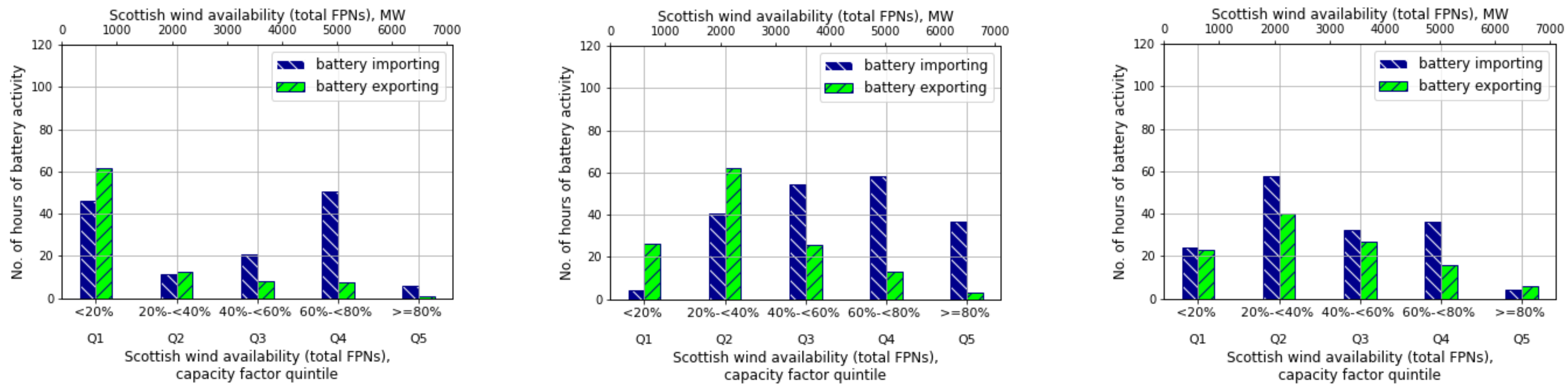
	Summer	Autumn	Winter
Battery trading strategy and visibility window	"moderate / 25%", 21 hours	"busy / 40%", 22 hours	"busy / 40%", 9 hrs

Table 113 Aggregate duration of battery activity, and of wind quintile duration, for each wind quintile and season. “Flow battery”: 12-hour battery, 70% round trip, “best cashflow” scenarios

	Aggregate duration of battery activity, and of wind conditions, hours								
	Summer			Autumn			Winter		
Wind energy availability quintile	Battery imports	Battery exports	Total hours	Battery imports	Battery exports	Total hours	Battery imports	Battery exports	Total hours
Q1	46.3	61.5	399	4.4	26.0	84	24.0	23.0	181
Q2	11.1	12.4	183	40.4	62.0	256	57.7	40.0	317
Q3	20.6	8.0	92	54.1	25.8	234	32.3	26.8	150
Q4	50.7	7.4	155	58.4	13.0	196	36.4	15.9	167
Q5	6.0	1.0	11	36.6	3.0	70	4.0	5.6	25
total	134.7	90.3	840	194.0	129.8	840	154.4	111.3	840

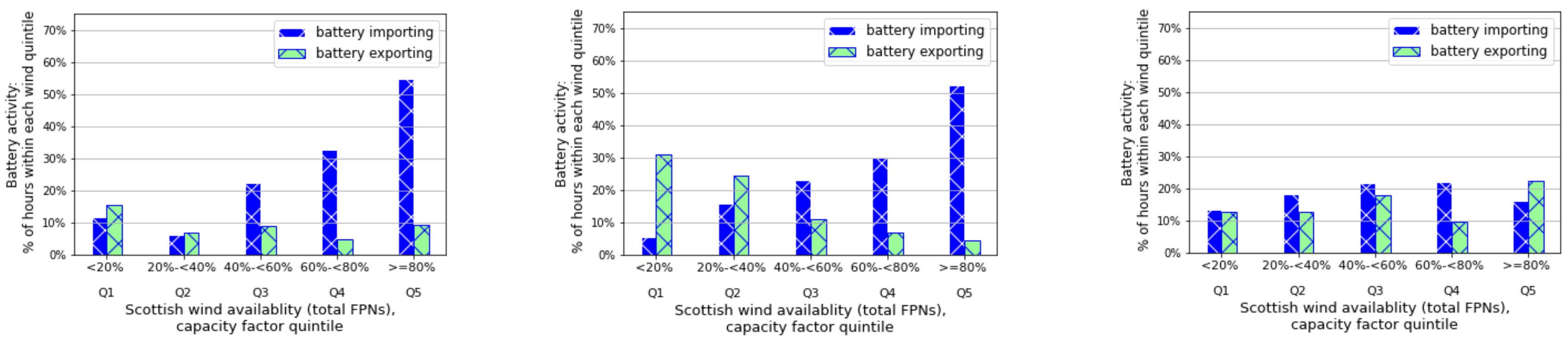
Table 114 Battery activity duration, as a percentage of duration of respective wind energy quintile, for each season. “Flow battery”: 12-hour battery, 70% round trip, “best cashflow” scenarios

Wind energy availability quintile	Proportional duration of battery activity, as a percentage of the duration of wind quintile conditions					
	Summer		Autumn		Winter	
	imports	exports	imports	exports	imports	exports
Q1	11.6%	15.4%	5.3%	31.0%	13.3%	12.7%
Q2	6.1%	6.8%	15.8%	24.2%	18.2%	12.6%
Q3	22.4%	8.7%	23.1%	11.0%	21.5%	17.9%
Q4	32.7%	4.8%	29.8%	6.6%	21.8%	9.5%
Q5	54.5%	9.1%	52.2%	4.3%	16.0%	22.4%



(a) Summer (b) Autumn (c) Winter

Figure 170 Aggregate durations of battery imports and exports during each wind energy availability quintile (tabulated in Table 113). Summer, Autumn and Winter case studies. "Flow battery" (12-hour battery, 70% round trip efficiency, "best cashflow" scenario[105] for each season



(a) Summer (b) Autumn (c) Winter

Figure 171 Proportional durations of battery imports and exports, i.e. duration of battery activity as a percentage of each respective wind quintile duration (tabulated in Table 114). Summer, Autumn and Winter case studies. "Flow battery" (12 hrs, 70% round trip), "best cashflow" scenario for each season

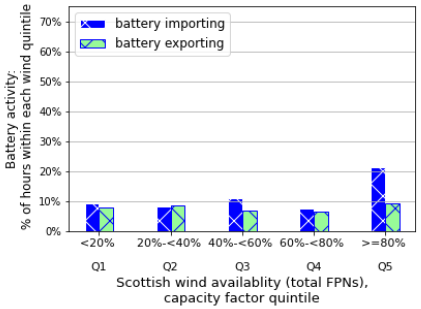
[105] Battery simulation trading parameters are shown in Table 112.

Chapter 5 Annex 5

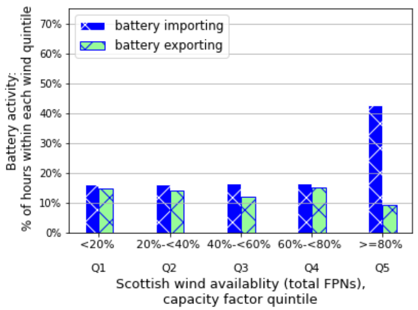
Battery activity charts, grouped by season

Aggregate durations of battery imports and exports as a proportion of duration of respective wind quintile conditions, for all batteries described in preceding annex. All batteries have 85% round-trip efficiency unless otherwise stated; all simulations are “best cashflow” scenarios, unless otherwise stated

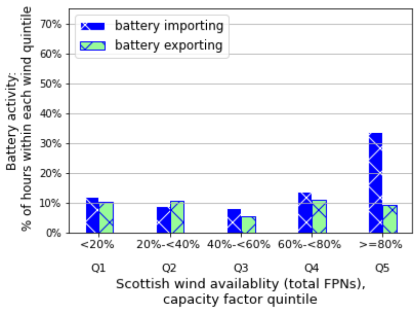
5.1 Summer



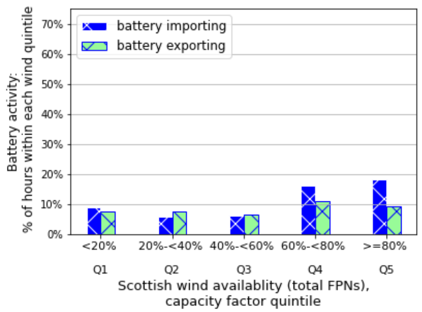
1 hr battery



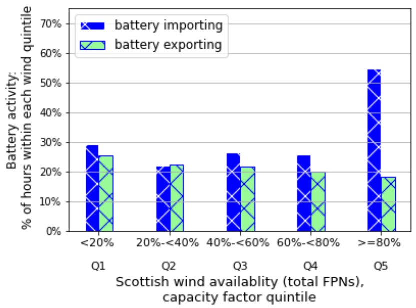
2 hr battery,
“best cashflow” scenario



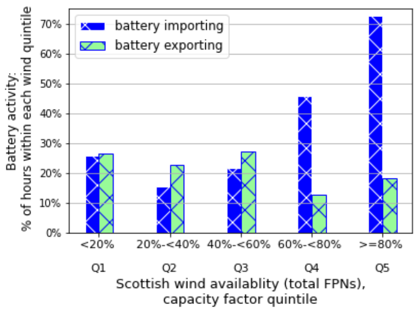
2 hr battery,
“lower cycling” scenario



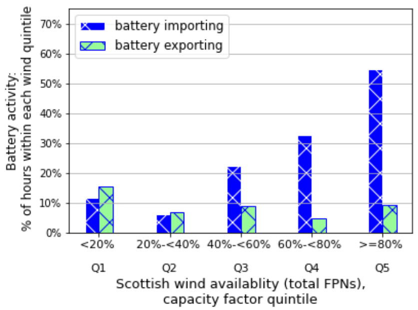
2hr battery,
“lowest cycling” scenario



4 hr battery



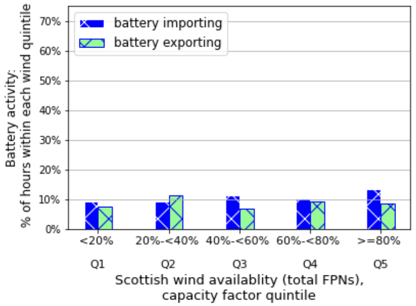
12 hr battery



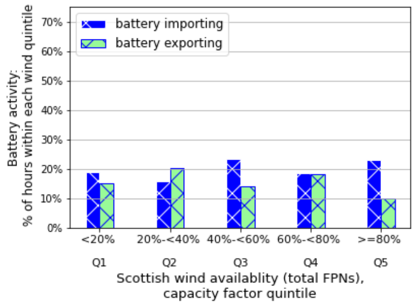
“flow battery”
12 hr, 70% round trip eff.

Figure 172 Battery activity by wind energy quintile, as a proportion of duration of respective quintile. Summer case study season, all batteries.

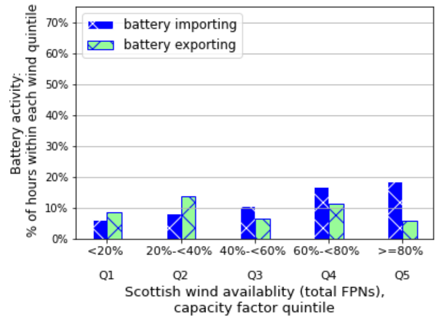
5.2 Autumn



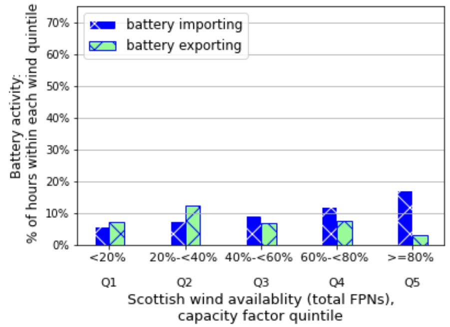
1 hr battery



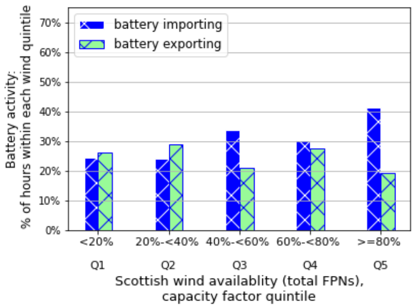
2 hr battery,
"best cashflow" scenario



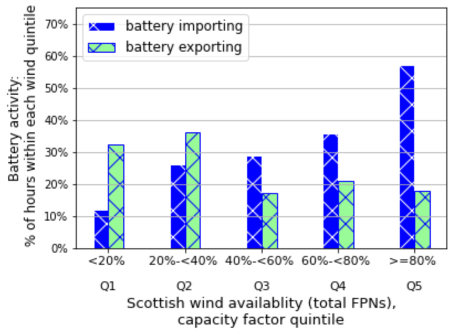
2 hr battery,
"lower cycling" scenario



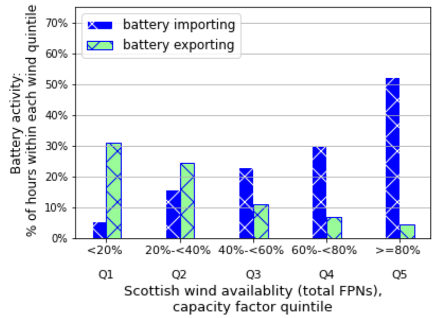
2hr battery,
"lowest cycling" scenario



4 hr battery



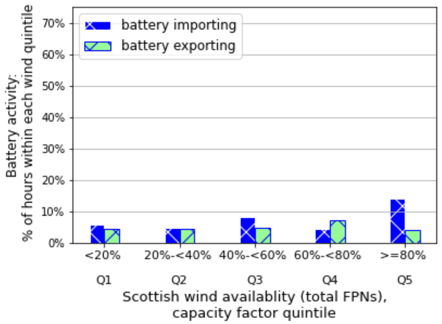
12 hr battery



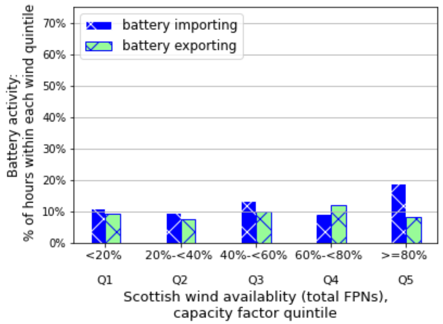
"flow battery":
12 hr, 70% round trip eff.

Figure 173 Battery activity by wind energy quintile, as a proportion of duration of respective quintile. Autumn case study season, all battery durations. All simulations "best cashflow" scenarios unless otherwise stated.

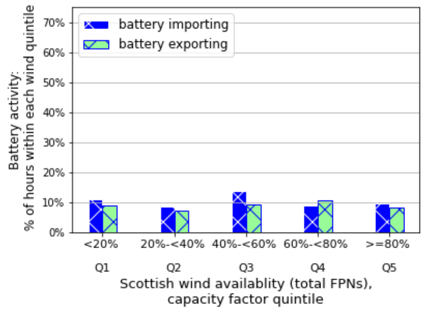
5.3 Winter



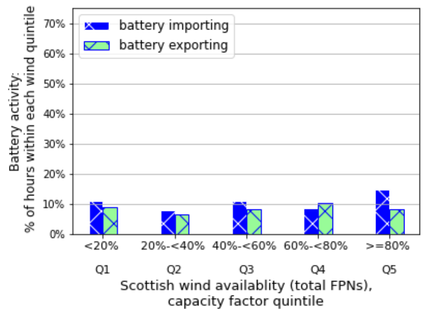
1 hr battery



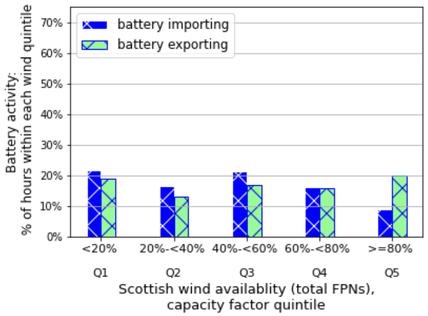
2 hr battery,
“best cashflow” scenario



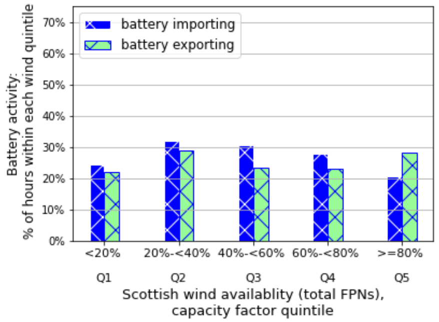
2 hr battery,
“lower cycling” scenario



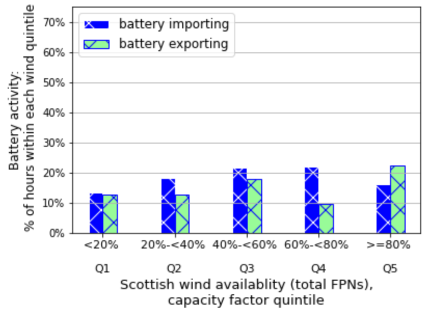
2hr battery,
“lowest cycling” scenario



4 hr battery



12 hr battery



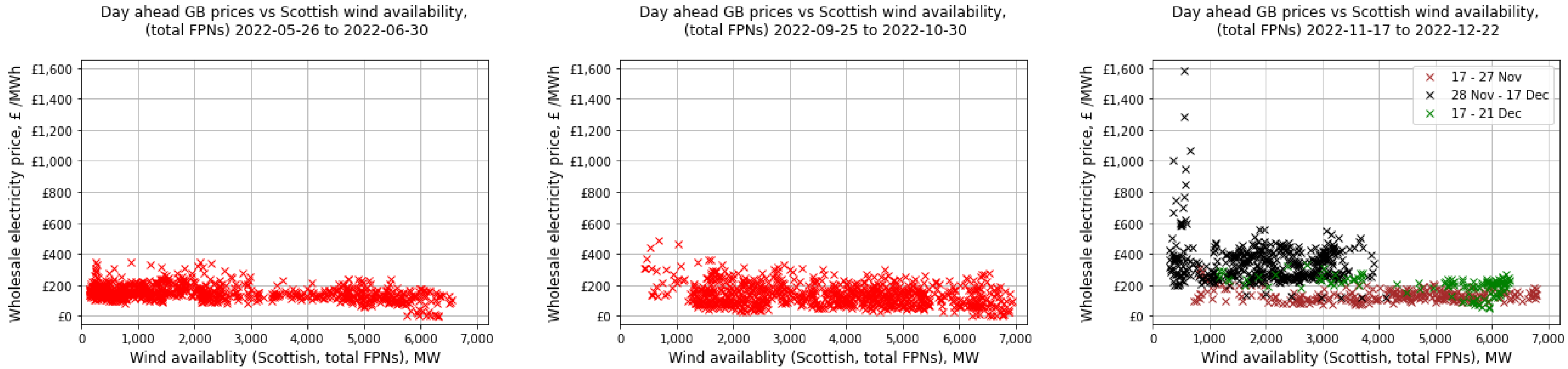
“flow battery”:
12 hr, 70% round trip eff.

Figure 174 Battery activity by wind energy quintile, as a proportion of duration of respective quintile. Winter case study season, all batteries.

Chapter 5 Annex 6

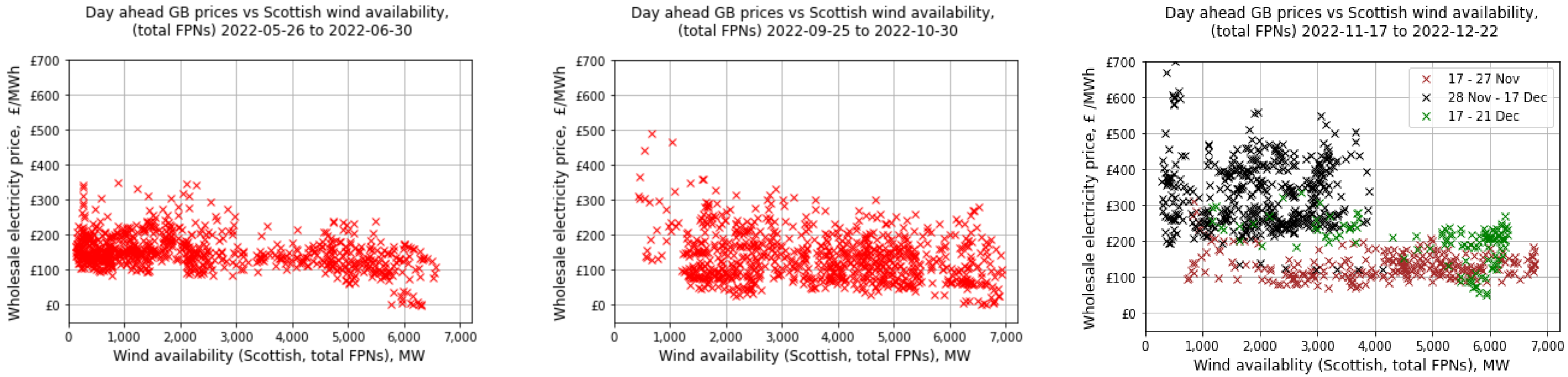
Scatterplots of wholesale electricity price vs wind metrics and other variables

6.1 Wholesale price vs Scottish wind availability (FPNs)



Summer Autumn Winter

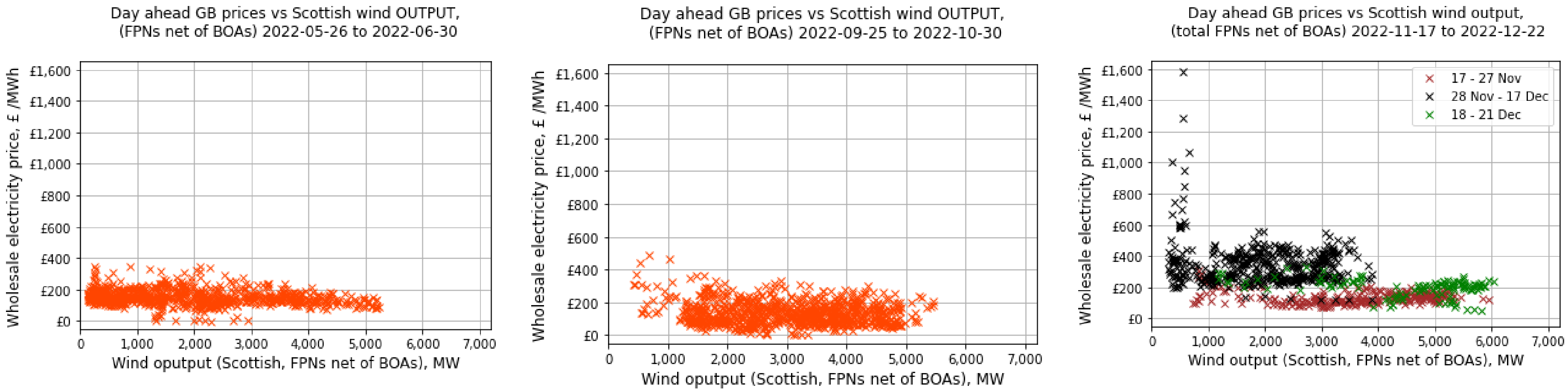
Figure 175 Wholesale price vs Scottish wind availability (aggregate wind FPNs). Scatterplots: summer, autumn, winter.



Summer Autumn Winter

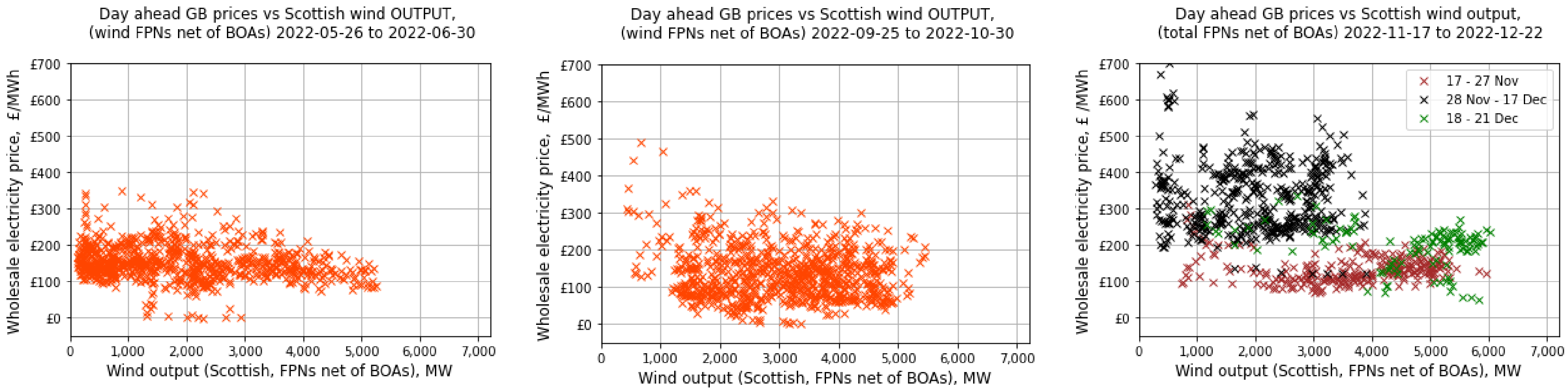
Figure 176 Wholesale price vs Scottish wind availability (aggregate wind FPNs). Scatterplots: summer, autumn, winter. Plots with larger price scale.

6.2 Wholesale price vs estimated Scottish wind outputs (FPNs net of BAVs and OAVs)



Summer Autumn Winter

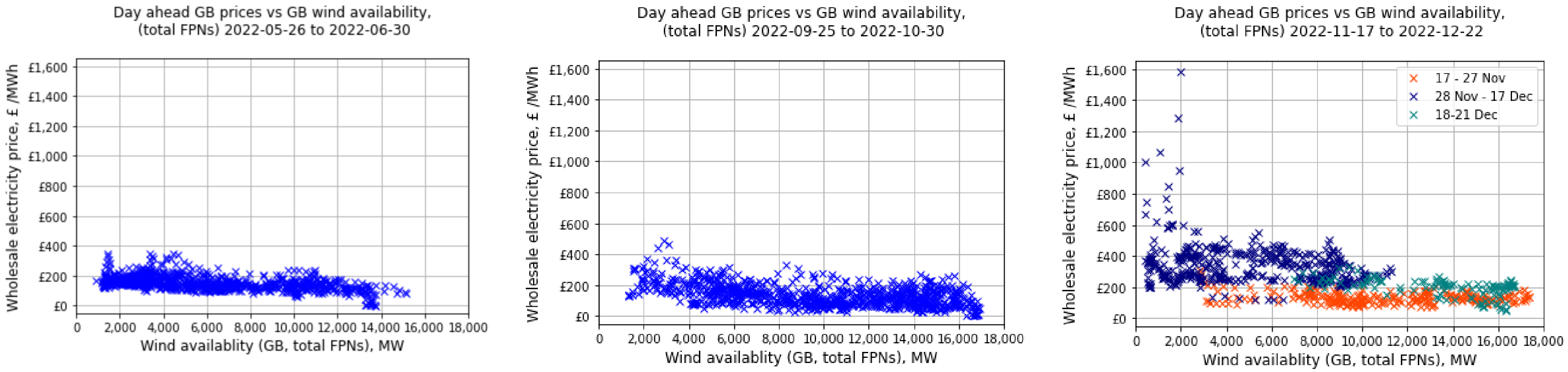
Figure 177 Wholesale price vs estimated Scottish wind output (aggregate Scottish wind FPNs net of BOAs). Scatterplots: summer, autumn, winter.



Summer Autumn Winter

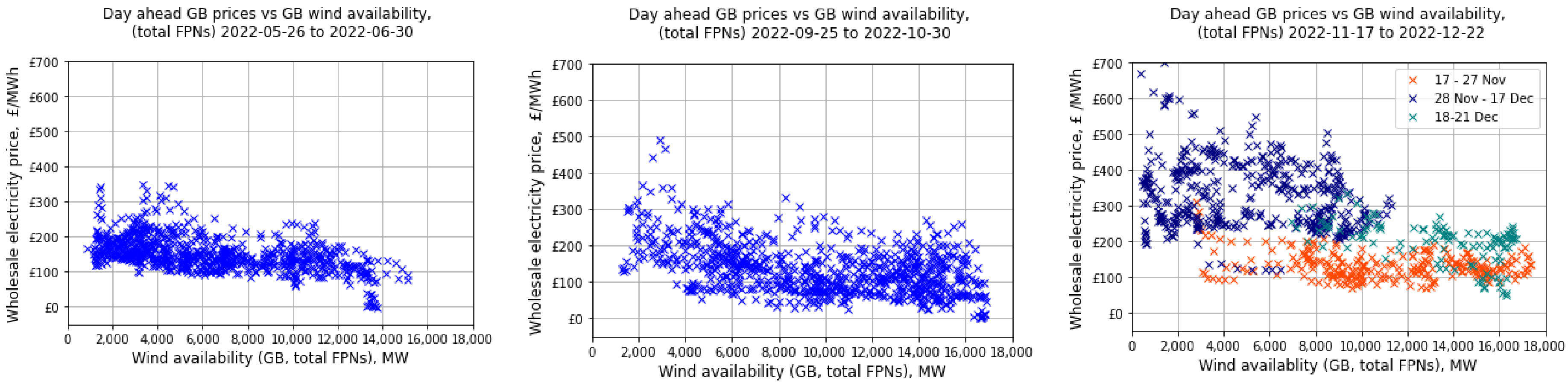
Figure 178 Wholesale price vs estimated Scottish wind output (aggregate Scottish wind FPNs net of BOAs). Scatterplots: summer, autumn, winter. Plots with larger price scale.

6.3 Wholesale price vs GB wind availability (GB wind FPNs)



Summer Autumn Winter

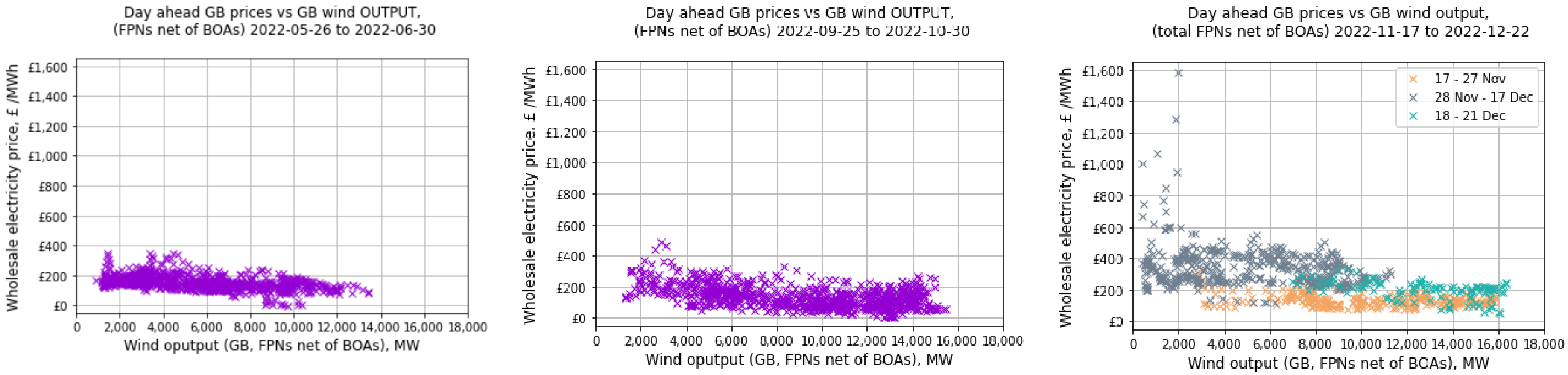
Figure 179 Wholesale price vs GB wind availability (aggregate wind FPNs). Scatterplots: summer, autumn, winter.



Summer Autumn Winter

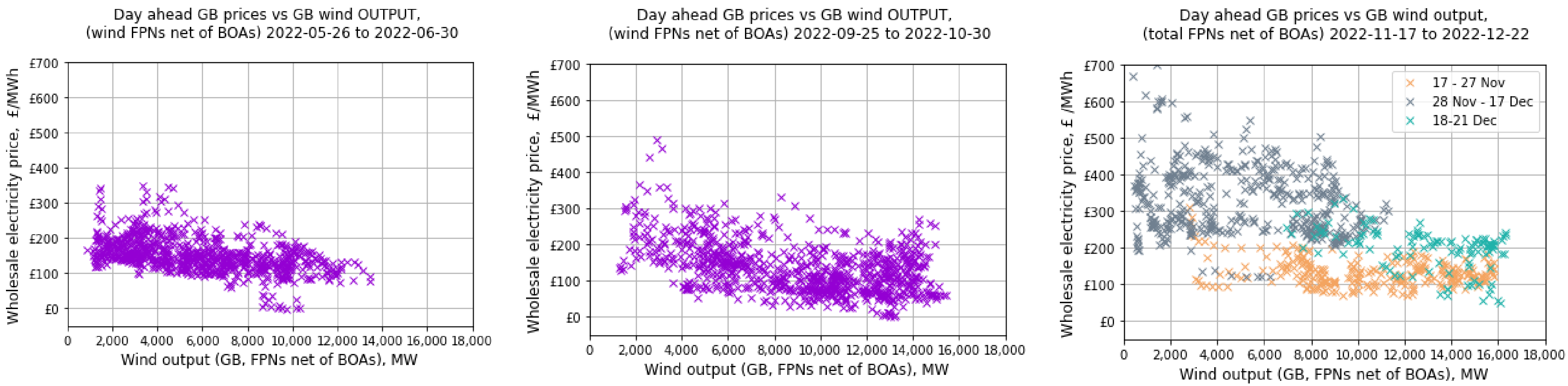
Figure 180 Wholesale price vs GB wind availability (aggregate wind FPNs). Scatterplots: summer, autumn, winter. Larger price scale.

6.4 Wholesale price vs estimated GB wind outputs (GB wind FPNs net of BAVs and OAVs)



Summer Autumn Winter

Figure 181 Wholesale price vs estimated GB wind output (aggregate GB wind FPNs net of BOAs). Scatterplots: summer, autumn, winter.



Summer Autumn Winter

Figure 182 Wholesale price vs estimated GB wind output (aggregate GB wind FPNs net of BOAs). Scatterplots: summer, autumn, winter. Larger price scale.

6.5 Wholesale price vs estimated Scottish wind curtailment (Scottish net BAVs)

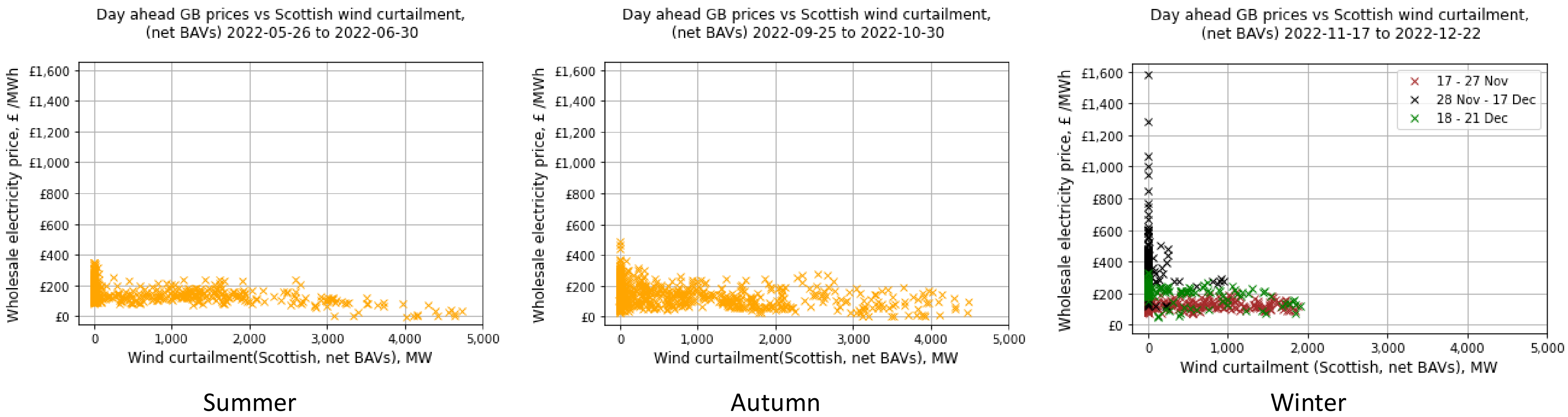


Figure 183 Wholesale price vs Scottish wind curtailment (aggregate Scottish wind BOAs). Scatterplots: summer, autumn, winter.

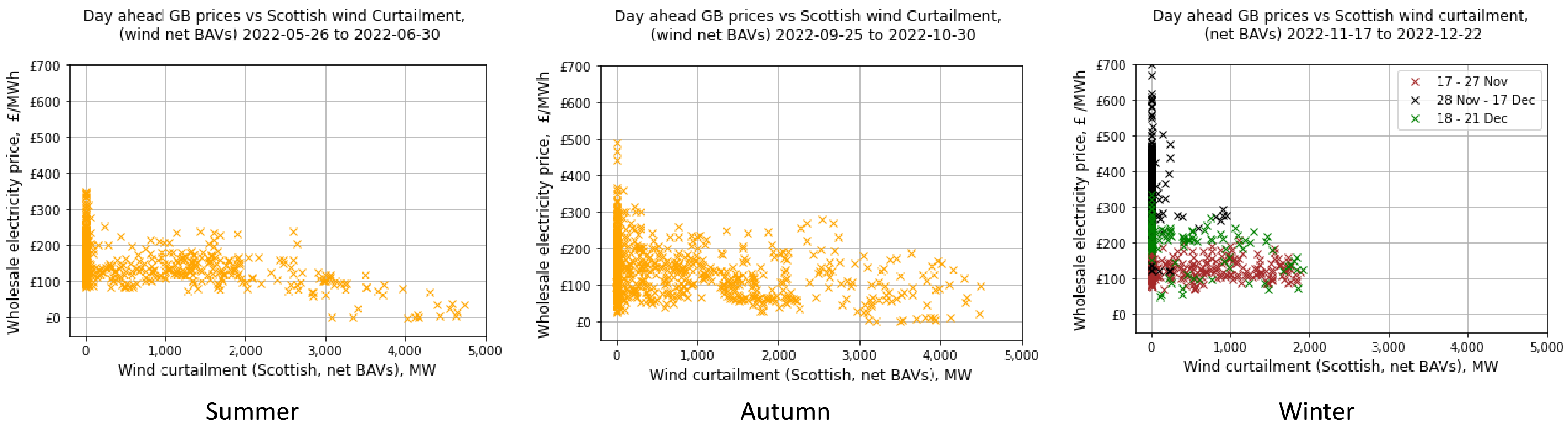


Figure 184 Wholesale price vs Scottish wind curtailment (aggregate Scottish wind BOAs). Scatterplots: summer, autumn, winter. Larger price scale

6.6 Wholesale price vs estimated GB wind curtailment (GB net BAVs)

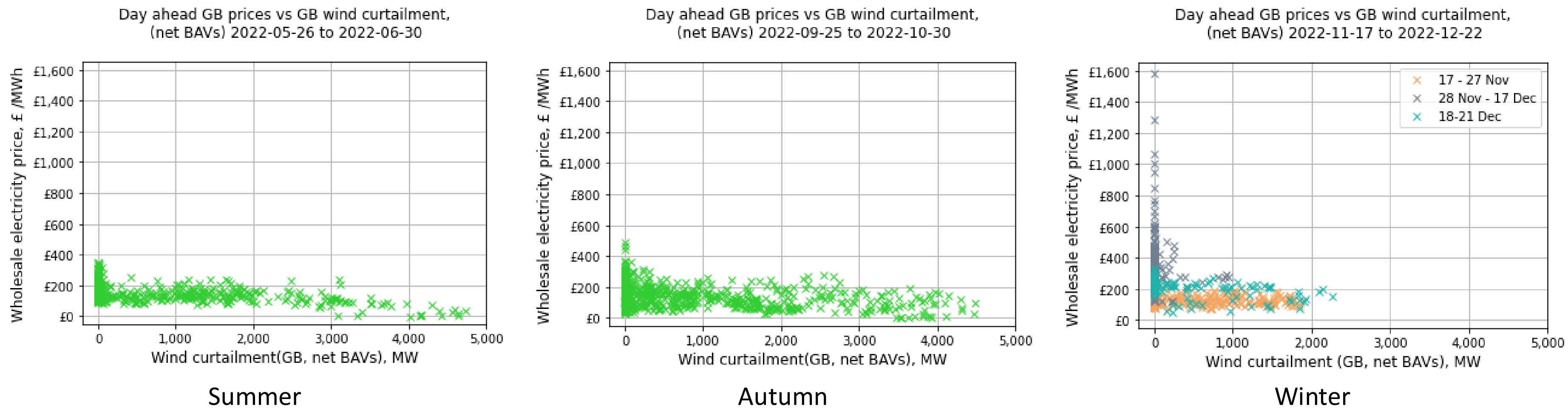


Figure 185 Wholesale price vs GB wind curtailment (aggregate GB wind BOAs). Scatterplots: summer, autumn, winter.

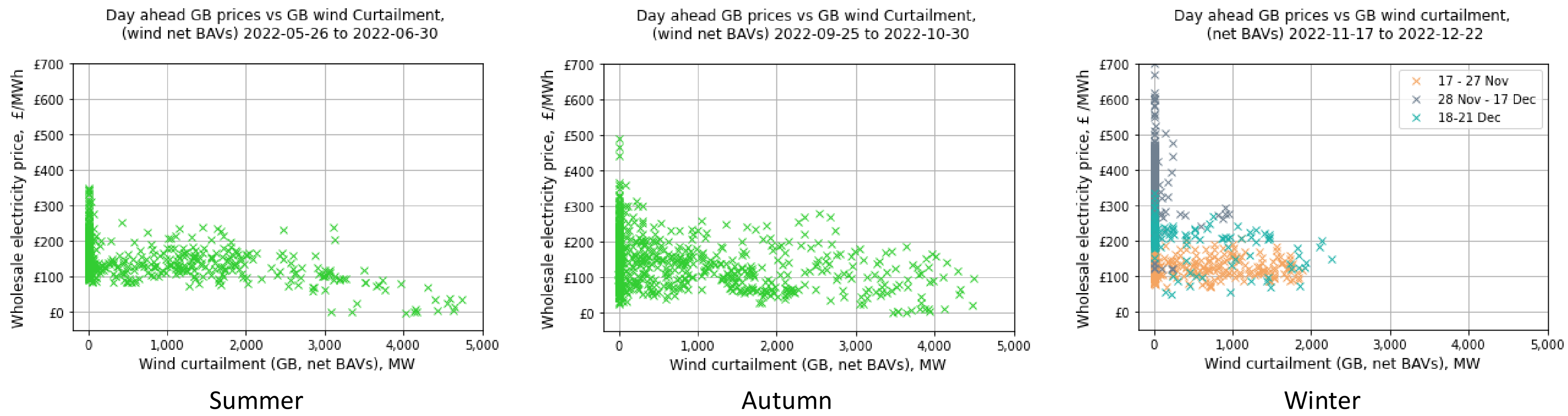
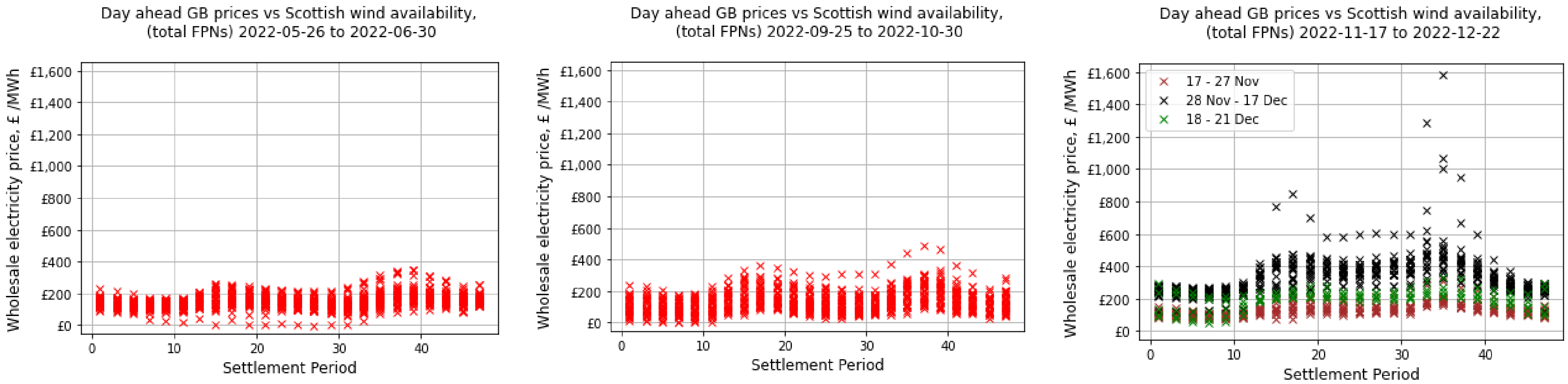


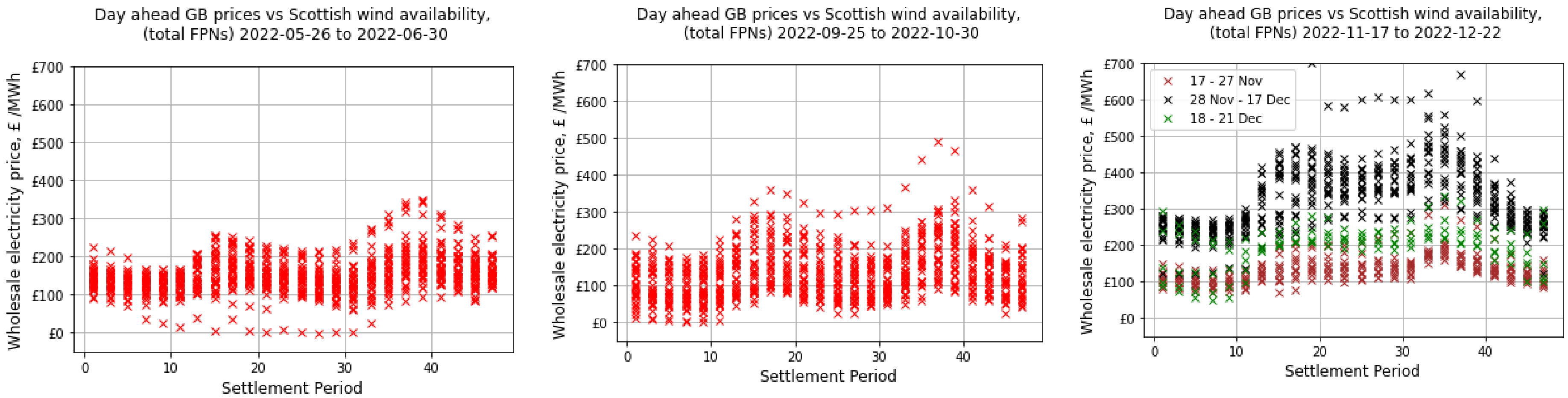
Figure 186 Wholesale price vs GB wind curtailment (aggregate GB wind BOAs). Scatterplots: summer, autumn, winter. Larger price scale.

6.7 Wholesale electricity price vs time of day (Settlement Period)



Summer Autumn Winter

Figure 187 Scatterplots of wholesale price vs time of day (Settlement Period): summer, autumn, winter.



Summer Autumn Winter

Figure 188 Scatterplots of wholesale price vs time of day (Settlement Period): summer, autumn, winter. Larger price scale

6.8 Wholesale electricity price vs Transmission System Demand (TSD) [17]

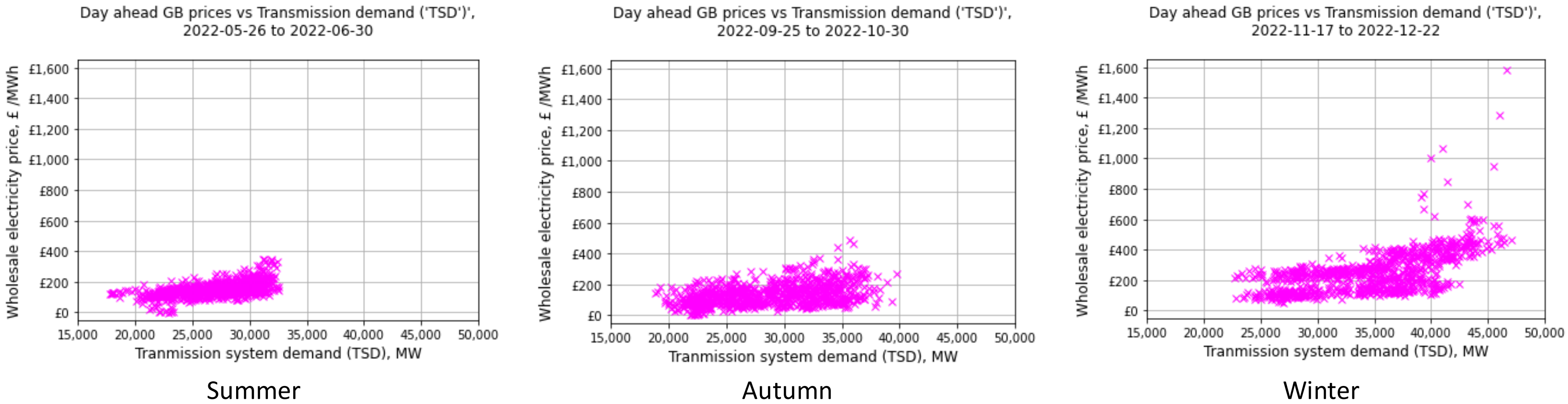


Figure 189 Scatterplots of wholesale price vs "Transmission System Demand". NESO data [17]; summer, autumn, winter

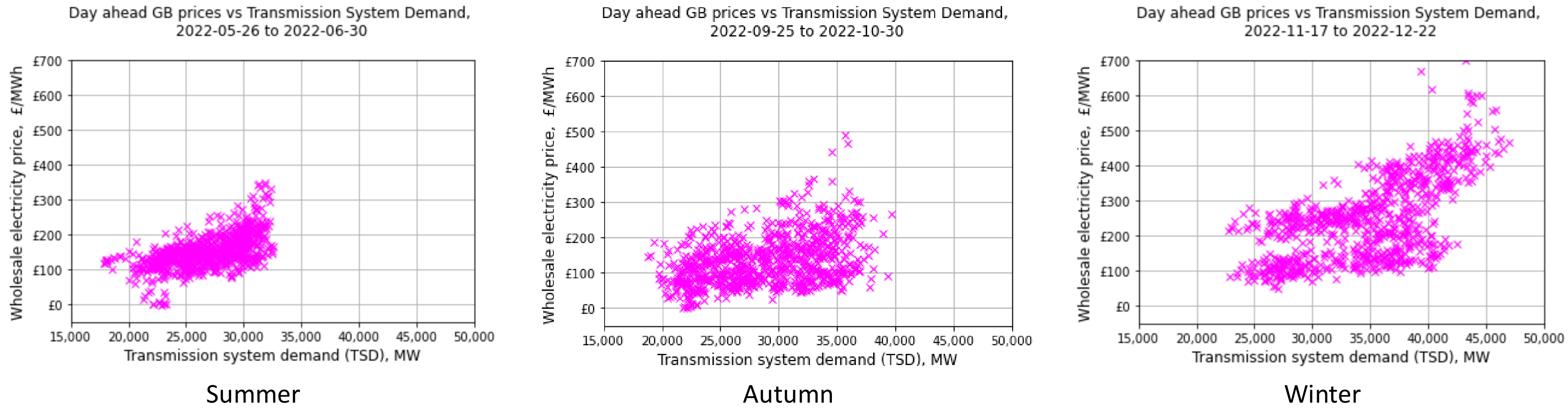


Figure 190 Scatterplots of wholesale price vs "Transmission System Demand". NESO data [17]; summer, autumn, winter. Larger price scale.

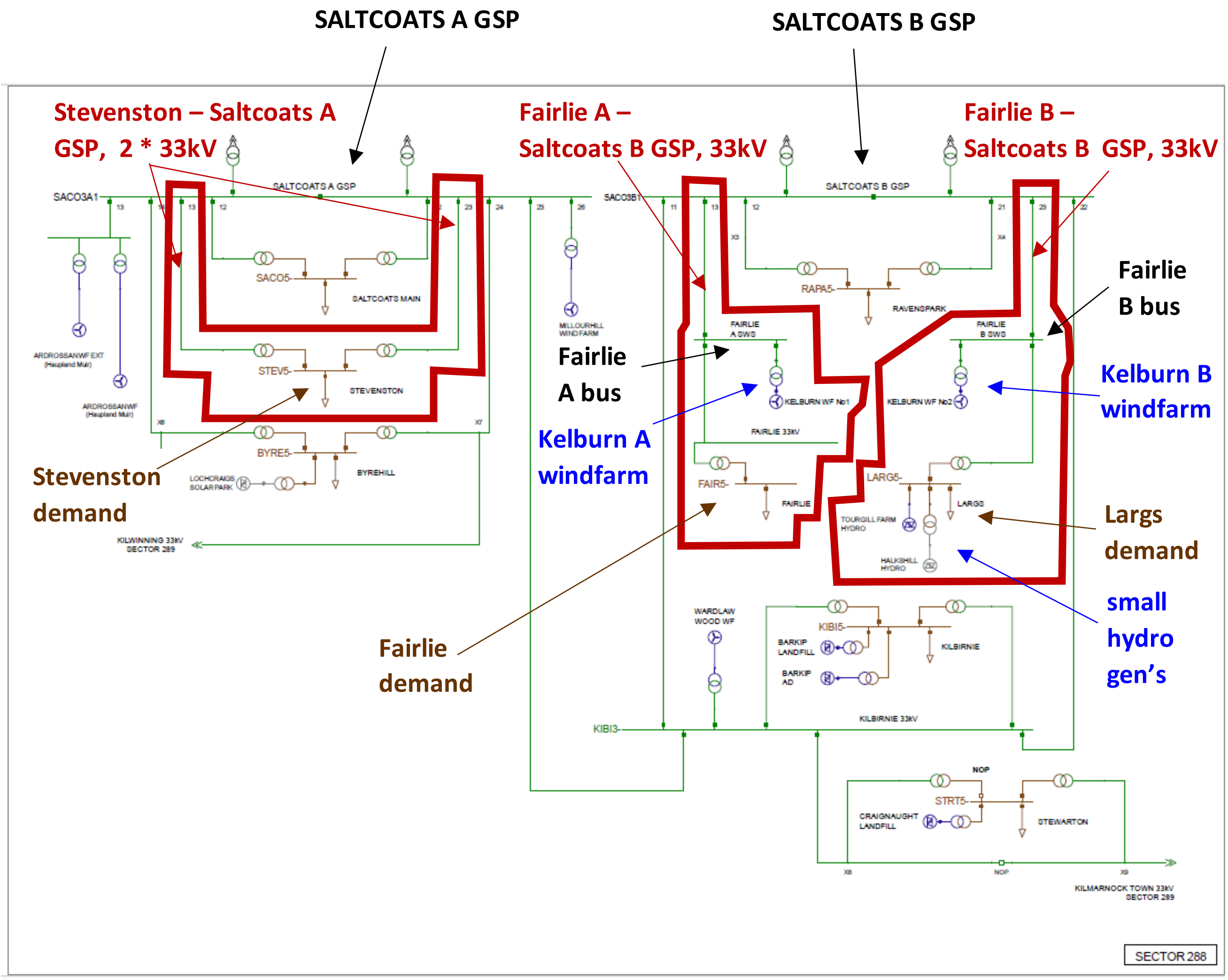
Annexes to Chapter 6. Potential effects of batteries on Distribution Network congestion in GB

Contents for Chapter 6 Annexes

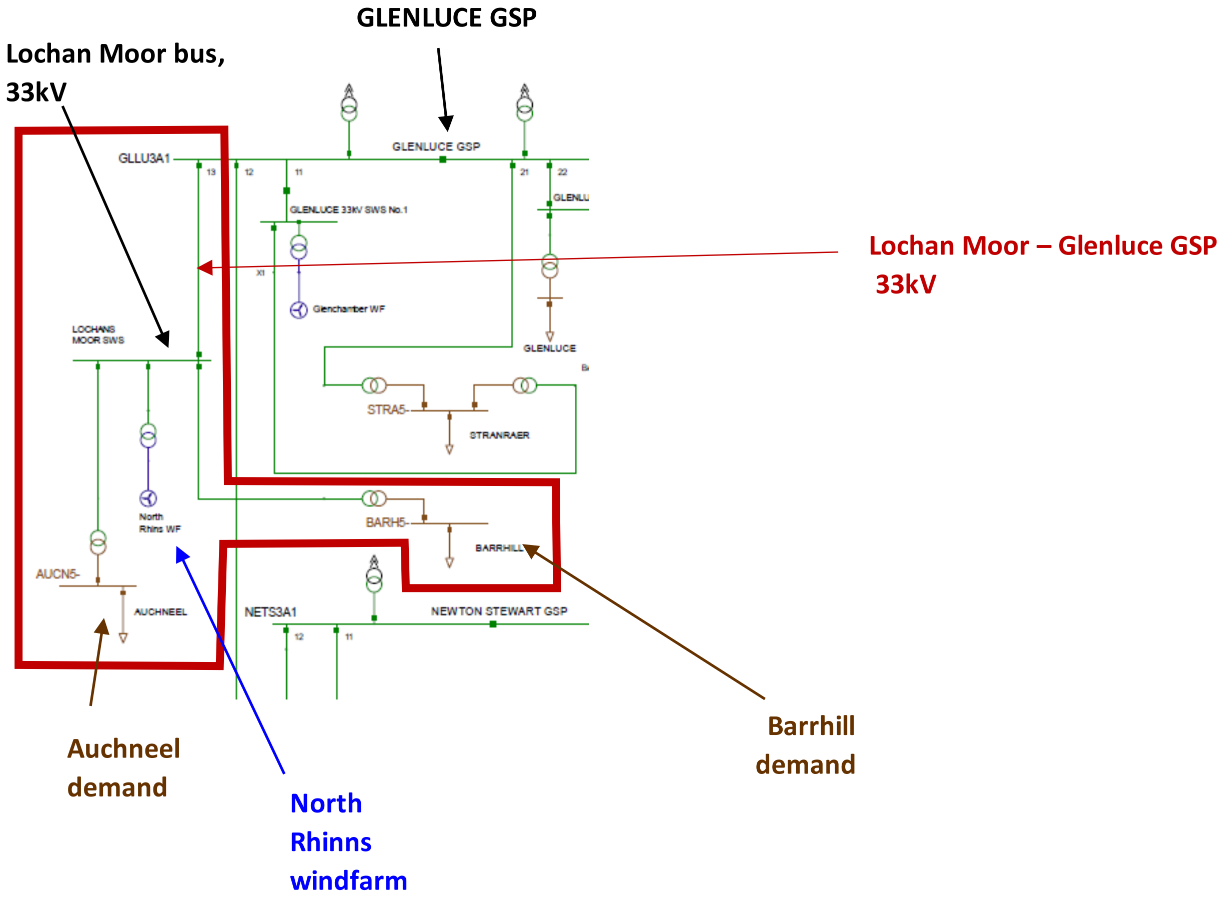
Tables for Chapter 6 Annexes

Chapter 6 Annex 1
Circuit diagrams for case study locations [229]

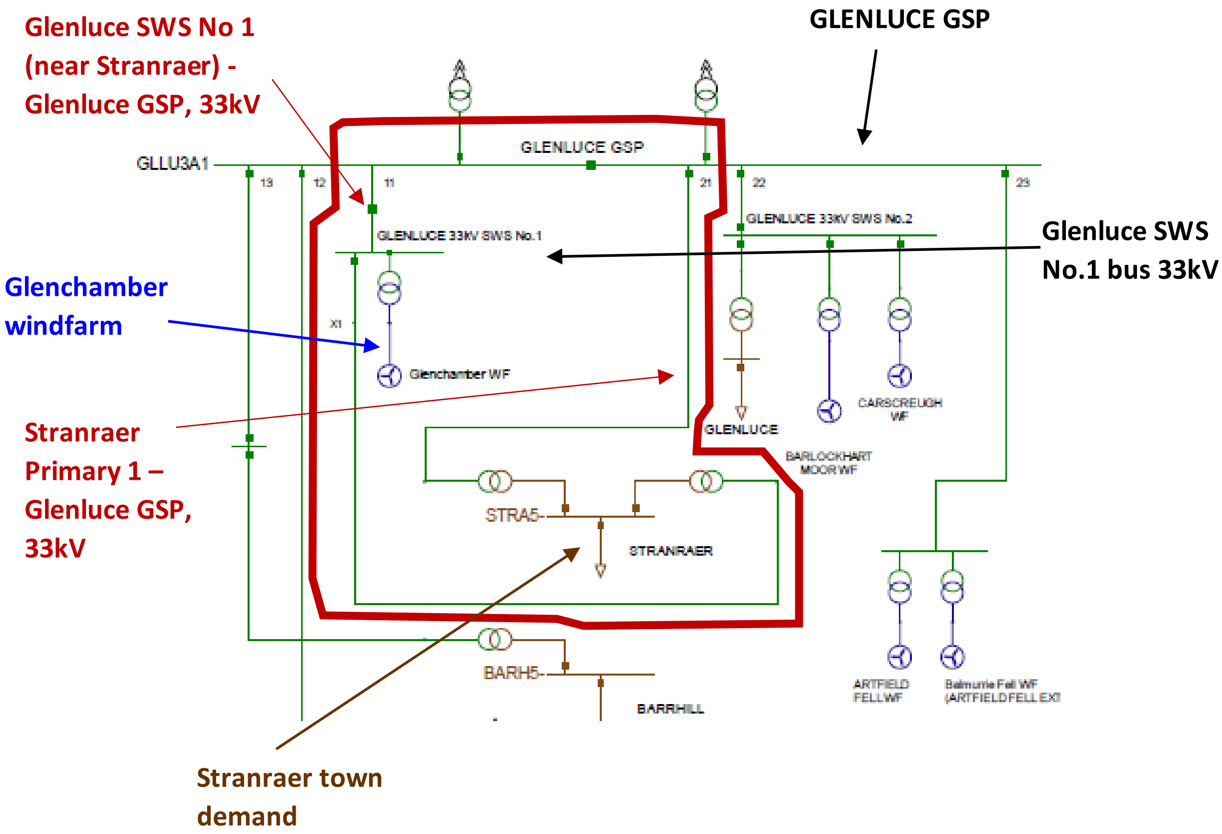
Largs, Fairlie and Stevenston



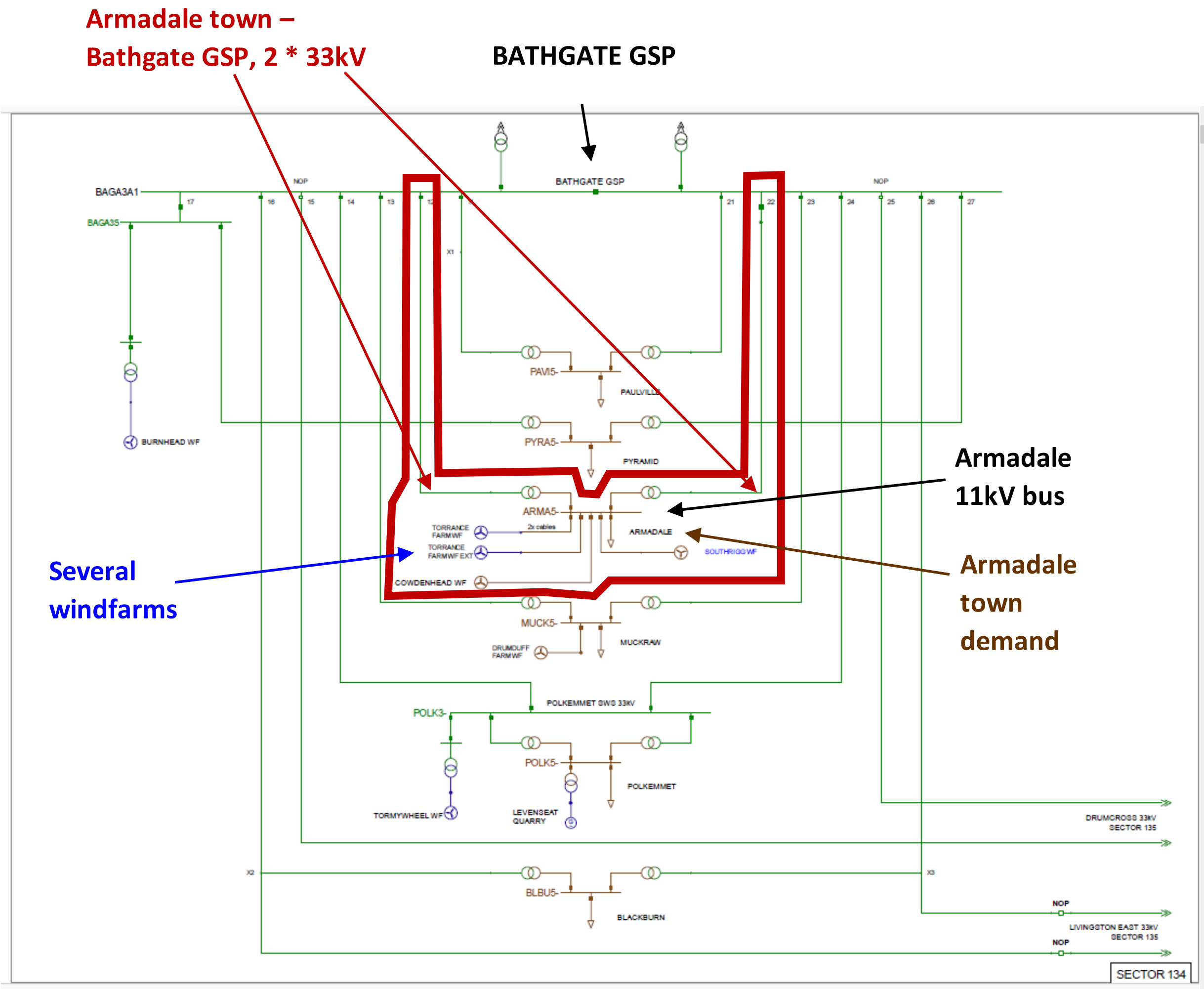
Lochan Moor


GLENLUCE GSP
Lochan Moor bus, 33kV
GLLU3A1
GLENLUCE GSP
GLENLUCE 33kV SWS No.1
Glenchamber WF
Lochan Moor – Glenluce GSP 33kV
LOCHANS MOOR SWS
GLENLUCE
STRA5-
STRANRAER
North Rhins WF
BARH5-
BARRHILL
AUCN5-
AUCHNEEL
NETS3A1
NEWTON STEWART GSP
Barrhill demand
Auchneel demand
North Rhinns windfarm

Stranraer town



Armadale


Armadale town –
Bathgate GSP, 2 * 33kV
BATHGATE GSP
Armadale
11kV bus
Several
windfarms
Armadale
town
demand
BAGA3A1
BAGA3S
BURNHEAD WF
BATHGATE GSP
NOP
PAVI5
PAULVILLE
PYRA5
PYRAMID
ARMA5
ARMADALE
TORRANCE FARM WF
TORRANCE FARMWF EXT
COWDENHEAD WF
SOUTHRIGG WF
MUCK5
MUCKRAW
DRUMDUFF FARMWF
POLKEMMET SWS 33kV
POLK3
POLK5
POLKEMMET
TORMYWHEEL WF
LEVENSEAT QUARRY
DRUMCROSS 33kV SECTOR 135
BLBU5
BLACKBURN
LIVINGSTON EAST 33kV SECTOR 135
SECTOR 134

Chapter 6 Annex 2

Data Cleaning – SPEN Open Data Portal

This annex describes minor changes which were made to the SPEN Data Portal datasets before their use in further analysis.

The data "metrics of interest" for all case study locations are shown in Table 115.

Table 115Case study locations: "metrics of interest" listed on SPEN Open Data Portal [234]

Location	Fairlie	Largs	Stevenston	Lochan Moor		Stranraer	Armadale
				Auchneel	Barrhill		
SPEN metrics of interest	Monitored flow, MW ('MF MW') Monitored Flow, MVAr ('MF MVAr') Current ('I Amps') Demand, MW						MF MW MF MVAr I Amps Demand, MW Generation, MW

The data portal lists "generation" values at all locations. For Fairlie, Stevenston, Auchneel, Barrhill and Stranraer, "generation" is always zero: there is no connected generation at those buses.

Largs does have two small hydro plants connected to its bus. For the whole of 2022, the data portal listed generation values as zero at all times. During 2023, the generation values listed were 1 MW (displayed as "-1"), from 1 Jan up to 1 June, and 0 MW thereafter.

Some "data cleaning" was needed before the data could be used.

First, there were a few occasions of multiple entries for the same timestep, requiring removal of duplicates, or averaging the values of metrics entered at the same time, if these metrics differed.

Then, there were two occasions of "missing data" in the 2023 dataset, i.e. a block of time without any data entries. For the occasion on 1 January, they were replaced with a copy of the data at the same time of day from the following day. For the period 27-28 August, this gap was filed with average of data values of the preceding and following days, at the same time of day.

There were a few brief instances when some or all of the data portal metrics fell to zero or other anomalously low values. These occasions were assumed to be monitoring faults, rather than descriptions of what actually happened. There were also occasions of "flat profiles", in which the metrics remained unchanged for a period of hours, days or in some cases, weeks. Where these occurred on buses with significant power flows (Largs),

For short durations of anomalous readings (up to 2 hours), the anomalous values were replaced by the average of the values of the preceding and following timesteps. For longer durations, an attempt was made to recreate a credible diurnal pattern, by using average values of the relevant metrics at the same time of day, for the days preceding and following the data disturbance.

Table 116 lists the dates and times when some or all SPEN's listed metrics of interest were assumed or suspected of being faulty, and notes which metrics were replaced, as described above. "Generation" values were only ever replaced at Armadale, and never at any of the other locations.

Particular attention was paid to data cleaning during the dates of battery case studies: 25 Sept-29 Oct 2022, 17 Nov – 21 Dec 2022, and 25 May- 28 June 2023 (the latter being used as a proxy for 26 May – 29 June 2022).

Table 116 SPEN Open Data Portal. Dates and times of data anomalies and data cleaning at case studies locations

Date	time	Data anomalies and Data Cleaning – metrics replaced						
		Fairlie	Largs	Stevenston	Lochan Moor		Stranraer	Armadale[106]
					Auchneel	Barrhill		
2022								
19 Sept	16:00-16:30	All	All	All	All	All	MF MW, Demand, I Amps	All
20 Sept	16:00-16:30	All	All	All	All	All	MF MW, Demand, I Amps	All
19 Oct	17:30-18:00	None	None	None	All	All	None	None
	18:00-20:00	None	None	None	None	All	None	None
14 Nov	15:00-15:30	I Amps and MF MVAr	All	All	All	All	All	All
15 Nov	15:00-15:30	I Amps and MF MVAr	All	All	All	All	MF MW, MF MVAr, Demand	All
19 Dec	15:00-15:30	All	All	All	All	None (flat data)	MF MW, Demand, I Amps.	All
19 Dec	17:30-18:00	All	All	All	All	None (flat data)	MF MW, Demand.	All
2023								
1 Jan	00:00-09:30	All: Missing data. Inserted data from following day						
11 Jan	15:00-15:30	None. I amps and MF MVAr dropout. MF MW & demand – flat values	MF MW, D	All	All	None: data dropout, but flow values v small, not worth replacing	MF MW, MF MVAr, Dem	All
12 Jan	09:30-10:00	None (flat data)	None	None	I Amps	None	None	None
12 Jan	10:00-10:30	None (flat data)	None	All	MF MW, Dem	None: poss. dropout, but flow values v small, not worth replacing	MF MW, Dem	Gen, Dem

106 "All" metrics excludes "Generation" at all locations other than Armadale.

DATE	TIME	Data Cleaning – metrics replaced at each location						
		FAIRLIE	Largs	Stevenston	Lochan Moor		Stranraer	Armadale
					Auchneel	Barrhill		
2023								
3 Feb	03:00-03:30	All	All	All	All	None: data dropout, but flow values v small, not worth replacing	All	All
3 Feb	23:00-24:00	None (flat data)	None	None	All	None (flat data)	None	None
4 Feb	00:00-16:00	None (flat data)	None	None	All	None (flat data)	None	None
8 Feb	12:00-24:00	None (flat data)	None	None	All	None: data dropout, but flow values v small, not worth replacing	None	None
9-11 Feb	All day	None (flat data)	None	None	All	None: data dropout, but flow values v small, not worth replacing	None	None
12 Feb	00:00-15:30	None (flat data)	None	None	All	None: data dropout, but flow values v small, not worth replacing	None	None
22 Mar	01:30-02:00	None (flat data)	None	None	None	None	None	Gen & Dem
22 Mar	02:00-03:00	None (flat data)	None	None	None	All – averaged values from duplicate rows of same timestamps	None	All
22 Mar	03:00-03:30	None (flat data)	None	None	None	None	None	Gen & Dem
24 Mar	11:00-11:30	None: I amps & MF MVAr dropout. Low values not worth replacing	MF MW, Dem	All	All	None: data dropout, but flow values v small, not worth replacing	All	All
24 Mar	12:30-13:00	None: I amps & MF MVAr dropout. Low values not worth replacing.	All	All	All	None: data dropout, but flow values v small, not worth replacing	All	All
17 Apr	04:30-05:00	None	None	None	None	None	None	All

		FAIRLIE	Largs	Stevenston	Lochan Moor		Stranraer	Armadale
					Auchneel	Barrhill		
2023								
2 May	15:00-16:00	None	All	None	None	None	None	None
3 May	16:30-17:00	None	None	None	All but MF MVAr	None: poss. dropout, but flow values v small, not worth replacing	None	None
9 May	04:30-05:00	None	None	None	All	None: poss. dropout, but flow values v small, not worth replacing	None	None
15 May	05:00-05:30	All	All	All	All	None: data dropout, but flow values v small, not worth replacing	All	All
21 May	05:00-05:30	All	All	All	All	None: data dropout, but flow values v small, not worth replacing	All	All
22 May	05:00-05:30	All	All	All	All	None: poss. dropout, but flow values v small, not worth replacing	All	All
22 May	15:00-15:30	None	None	None	I amps only	None: data dropout, but flow values v small, not worth replacing	None	None
22 May	15:30-16:00	None: I amps & MF MVAr dropout. Low values not worth replacing	MF MW, I amps, Dem	All	All	None: data dropout, but flow values v small, not worth replacing	MF MW, Dem	All
23 May	11:30-12:30	None: I amps & MF MVAr dropout. Low values not worth replacing.	MF MW, I amps, Dem	All	All	None: data dropout, but flow values v small, not worth replacing	All	All
5 Jun	05:00-05:30	None	None	None	None	None	None	All (after rescaling)
12 Jun	04:30-05:00	None	None	None	None	None	None	All

DATE	TIME	Data Cleaning – metrics replaced at each location						
		FAIRLIE	Largs	Stevenston	Lochan Moor		Stranraer	Armadale
					Auchneel	Barrhill		
2023								
18 Jun	05:00-05:30	All	All	All	All	None: data dropout, but flow values v small, not worth replacing	All	All
19 Jun	04:30-05:00	All	None	None	None	None: data dropout, but flow values v small, not worth replacing	None	All
20 Jun	05:00-05:30	None	None	None	None	None	None	All (after rescaling)
21 Jun	15:30-16:00	None: data dropout, but flow values v small, not worth replacing	All	All	All	None: poss. dropout, but flow values v small, not worth replacing	All	All
22 Jun	12:00-12:30	None (I amps & MF MVAr dropout. MF MW & Dem flat values)	All	All	All	None: data dropout, but flow values v small, not worth replacing	All	All
26 Jun	05:00-05:30	None	None	None	None	None	None	All (after rescaling)
26 Jun	09:30-24:00	None	All: Replaced flatlined values with diurnal pattern	None	None	None	None	None
27 Jun	00:00-18:00	None		None	None	None	None	None
27 Jun	18:30-19:00	None (flat data)	All (data dropout)	None	None	None	None	None
27 Jun	19:00-24:00	None	None. Retained low flow values. Possible high hydro output?	None	None	None	None	None
28 Jun	00:00-24:00	None. Flatlined data – but low values not worth replacing.		None	None	None	None	None

DATE	TIME	Data Cleaning – metrics replaced at each location						
		FAIRLIE	Largs	Stevenston	Lochan Moor		Stranraer	Armadale
					Auchneel	Barrhill		
2023								
29 Jun	08:00-19:00	None: poss. dropout, but flow values v small, not worth replacing	All: Replaced flatlined values with diurnal pattern	None	None	None	None	None
29 Jun	19:30-20:00	None (flat data)	All. V . low values suspected data dropout	None	None	None	None	None
17 Jul	05:00-05:30	All	All	All	All	None: data dropout, but flow values v small, not worth replacing	All	All
19 Jul	15:30-16:00	None: data dropout, but flow values v small, not worth replacing	All	All	All	None: data dropout, but flow values v small, not worth replacing	All	All
20 Jul	10:00-10:30	None	None	MF MW, Dem	All	None. Only I amps dropout	None	None
14 Aug	05:00-05:30	All	All	All	All	None: data dropout, but flow values v small, not worth replacing	All	All
16 Aug	16:00-16:30	None (flat data)	MF MW, Dem	All	All	None: data dropout, but flow values v small, not worth replacing	MF MW, I amps, Dem	None
18 Aug	12:00-12:30	None	None	None	None	None	None	All
18 Aug	13:00-13:30	None (Dropout of I amps and MVAr dropout. Very low MW flow values.)	MF MW, I amps, Dem	All	All	None: data dropout, but flow values v small, not worth replacing	MF MW, Dem	None
27 Aug	07:00-24:00	All – inserted missing day						
28 Aug	00:00-06:00							

There are several other instances of potentially anomalous data on small demand circuits, but which were not "cleaned":

- Fairlie: 28 October 2022, 08:30-18:00, and 29 December 2022, 00:00-03:00
- Barrhill: 24 Sept 2022 16:30-17:30, 27 Sept 17:30, 28 Sept 16:30 – 17:30, 30 Sept 14:00 – 24:00.

At Barrhill 11kV bus, there is a single value of Monitored Flow (MW) in 2022 from 17 Dec 21:00 up to the end of the year, with varying generation and demand. This data averaging may underestimate variations in demand, potentially causing an error up to around 0.5 MW.

There are a few instances of high demand spikes at Stevenston and Stranraer. These events have not been "cleaned" and are presumed to show faults or other potentially abnormal events, rather than monitoring glitches. Details are shown in Table 117.

Table 117Stevenston and Stranraer: anomalous spikes in Monitored Flow & Demand

Location	Date	time	Max demand[2], MW (half hourly value)	Max demand[107], MW, after smoothing to Hourly	Type of event	Case study period
Stevenston	8/12/22	17:30	13.08	12.96	"Normal" max, 2022	Winter
	17/10/22	18:30	11.037	10.2735	"normal" flow	Autumn
		19:00	14.556	14.5775	Suspected fault / abnormal event	
		19:30	14.599			
		20:00	13.974	16.8825		
		20:30	19.791			
		21:00	9.853	9.7995	"normal" flow	
Stranraer	9/12/22	17:30	10.727	10.2185	"Normal" max, 2022	winter
	4/9/22	18:30	17.527	11.649	Suspected faults / abnormal events	None
	17/12/22	20:30	14.141	10.5065		Winter
	23/12/22	12:30	14.105	10.766		None
		13:00	14.226	10.991		
	26/12/22	20:30	21.203	13.923		
	30/12/22	11:30	24.756	16.197		

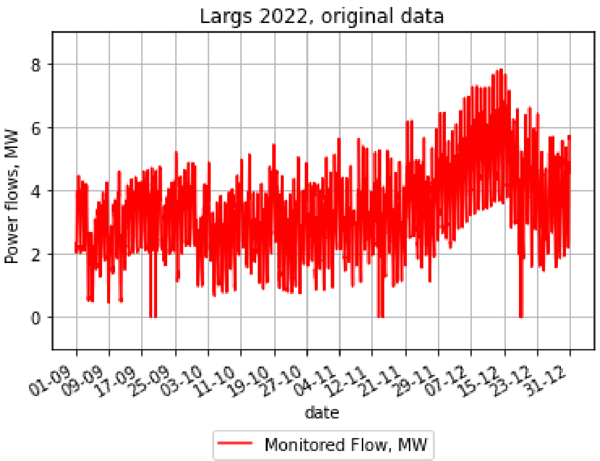
[107] In all cases listed in Table 117, Demand (MW) values were identical to the "Monitored Flow (MW)" values, at the stated place and time.

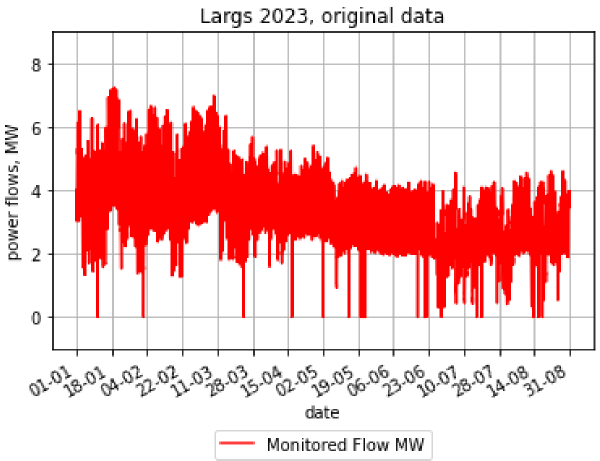
Chapter 6 Annex 3

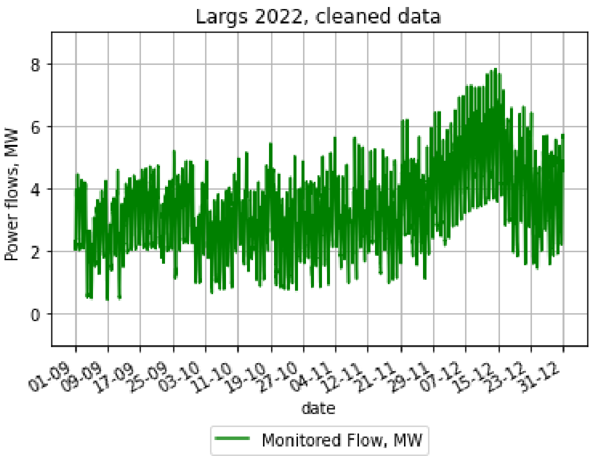
Timeseries of SPEN Open Data Portal Monitored Flows (MW) at case study locations, before and after “data cleaning”

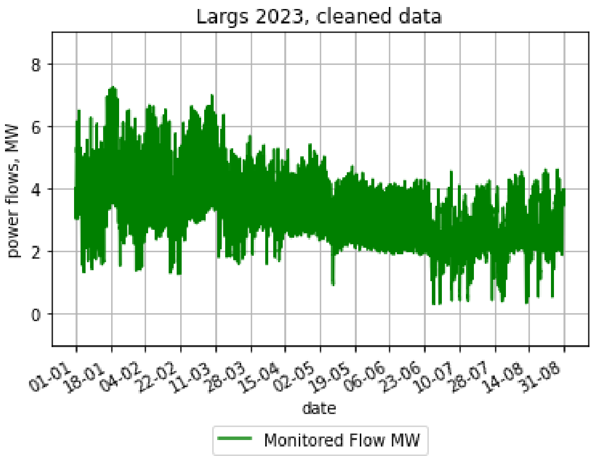
Largs “Monitored Flow” at11kV bus. Sept 2022 – Aug 2023, as downloaded (“original data”), and after “cleaning”.

(These datasets are used later in Chapter 7 for “network headroom” calculations.)



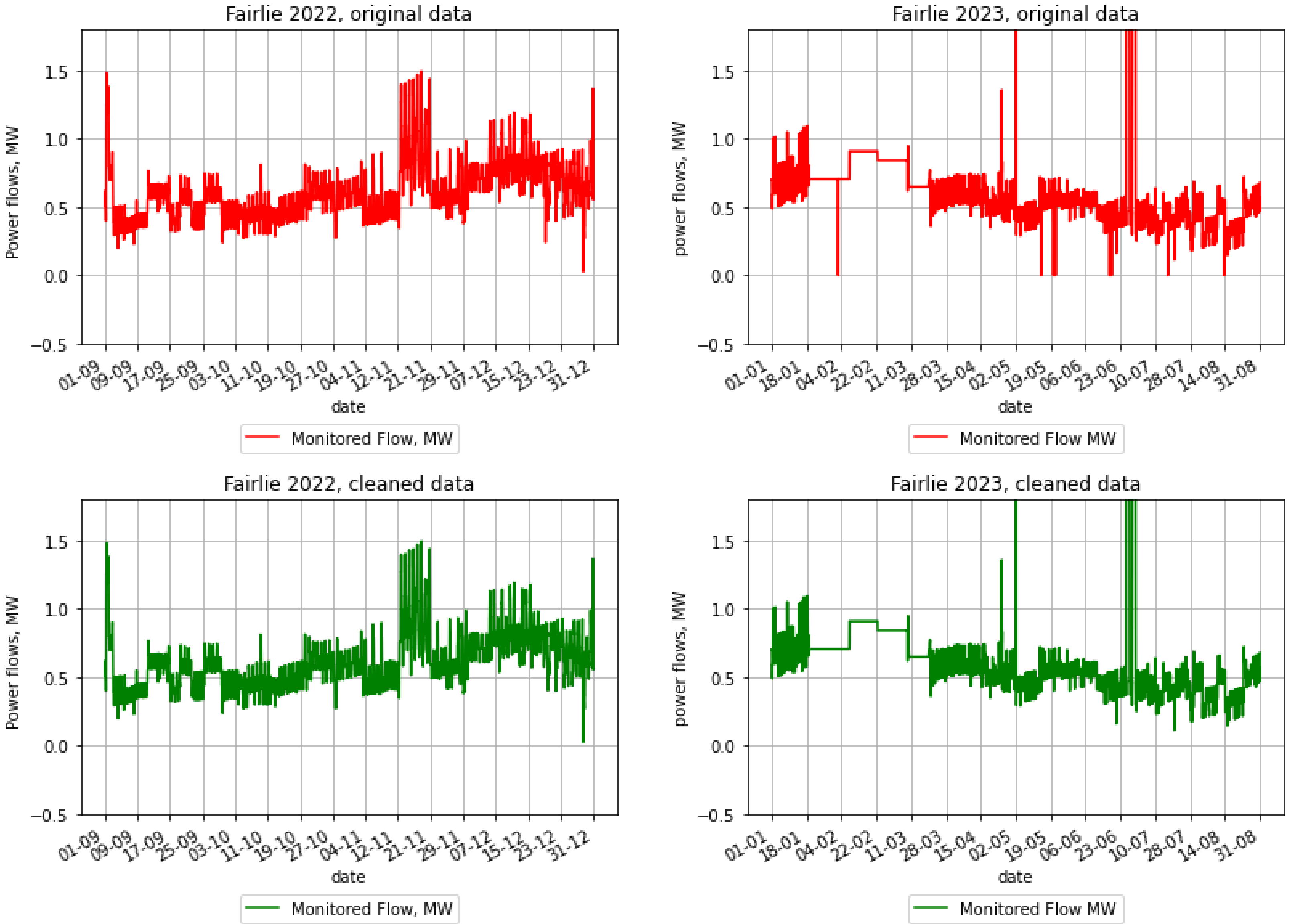




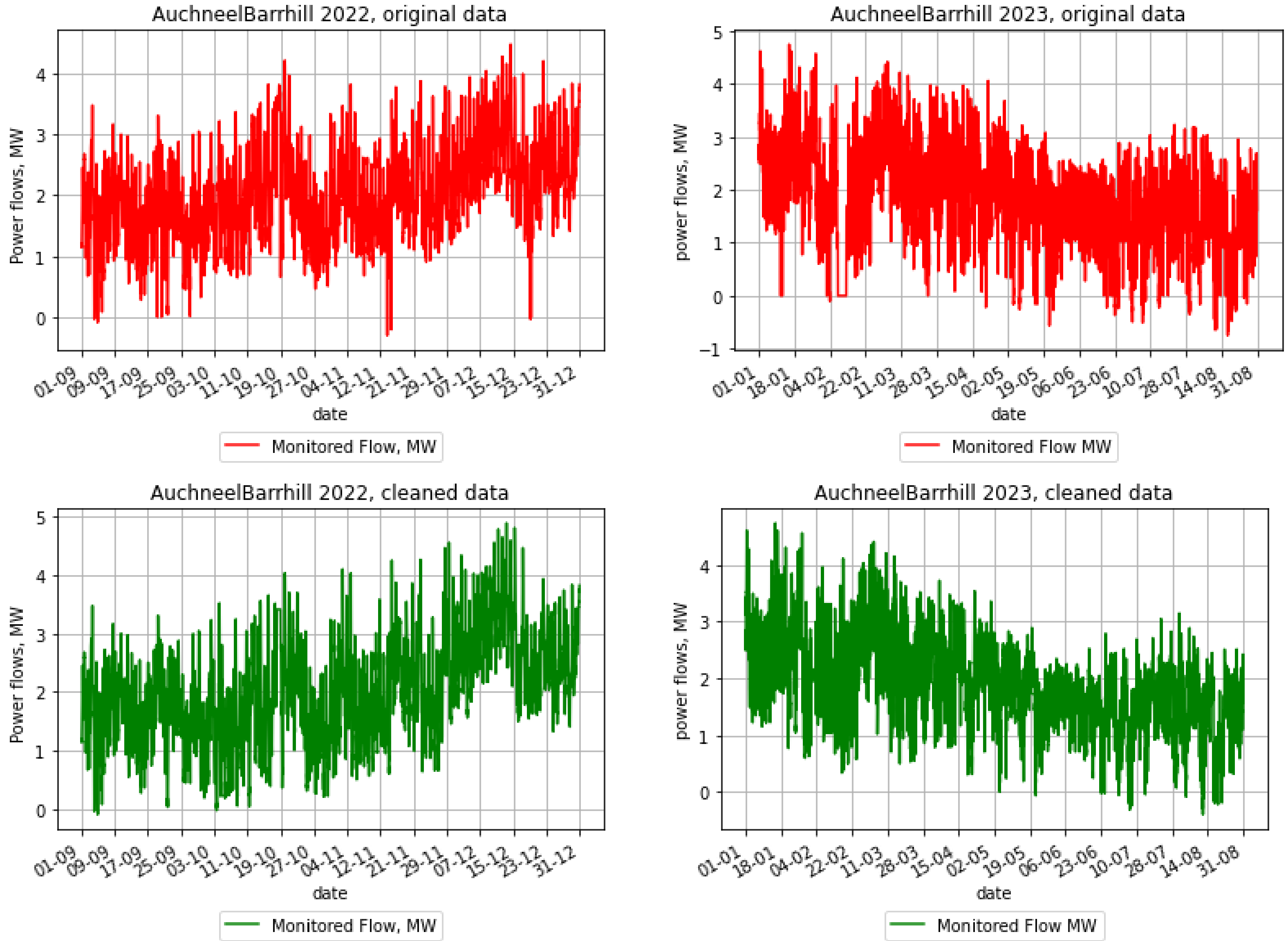


Fairlie Monitored Flow" at11kV bus. Sept 2022 – Aug 2023, as downloaded, and after "cleaning". Scaled to 6 MW.

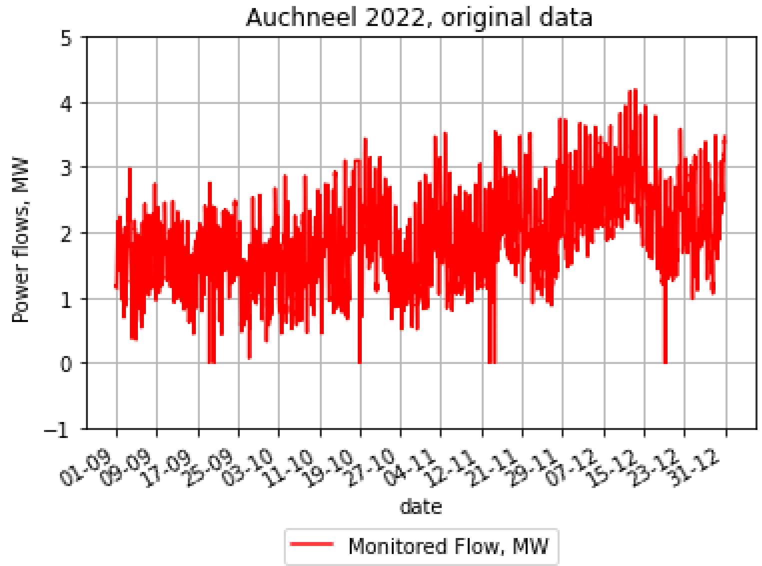
Fairlie "Monitored Flow" at11kV bus. Sept 2022 – Aug 2023, as downloaded, and after "cleaning". Scaled to 1.5 MW.

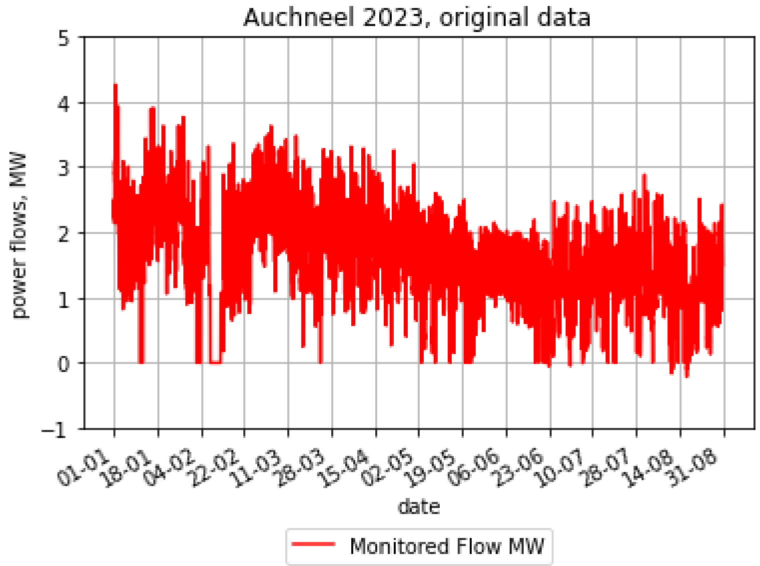


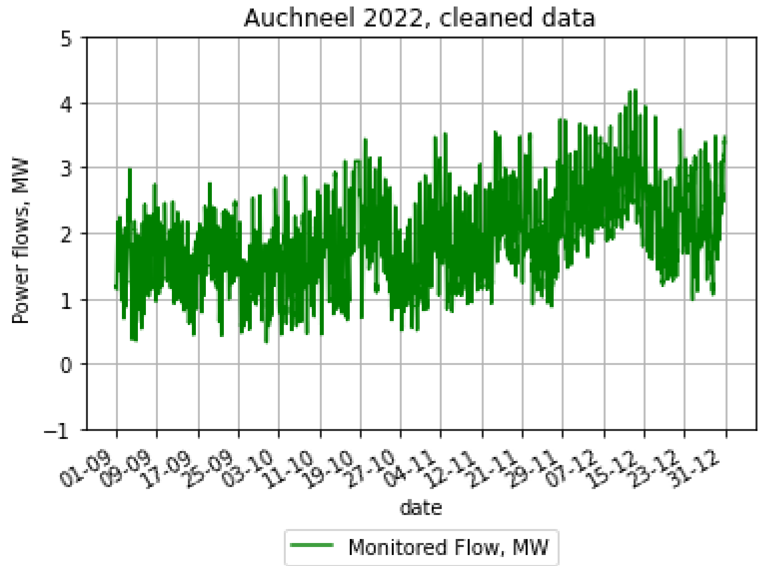
Lochan Moor flows: A combination of “Monitored Flows” flows from Auchneel and Barrhill 11kV buses, Sep 2022 – Aug 2023, as downloaded and after “cleaning”

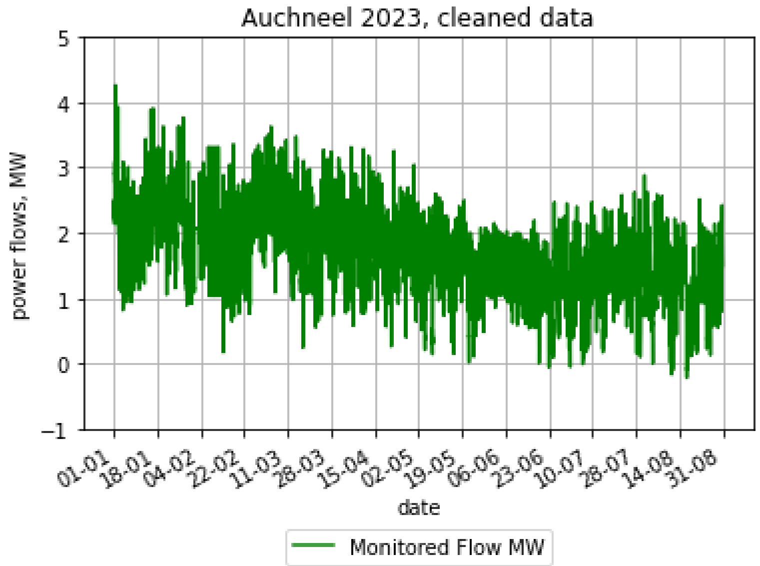


Auchneel "Monitored Flow" at11kV bus. Sept 2022 – Aug 2023, as downloaded, and after "cleaning". This is the larger contributor to Lochan Moor demand flows.

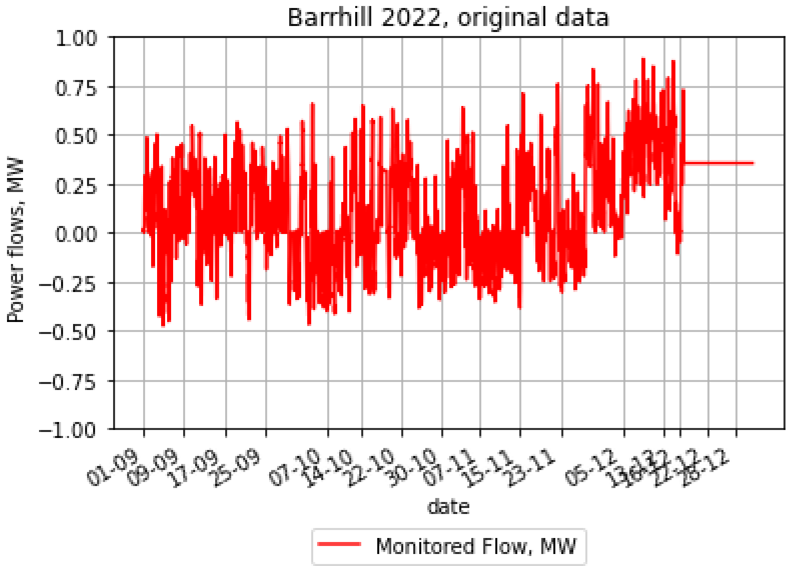


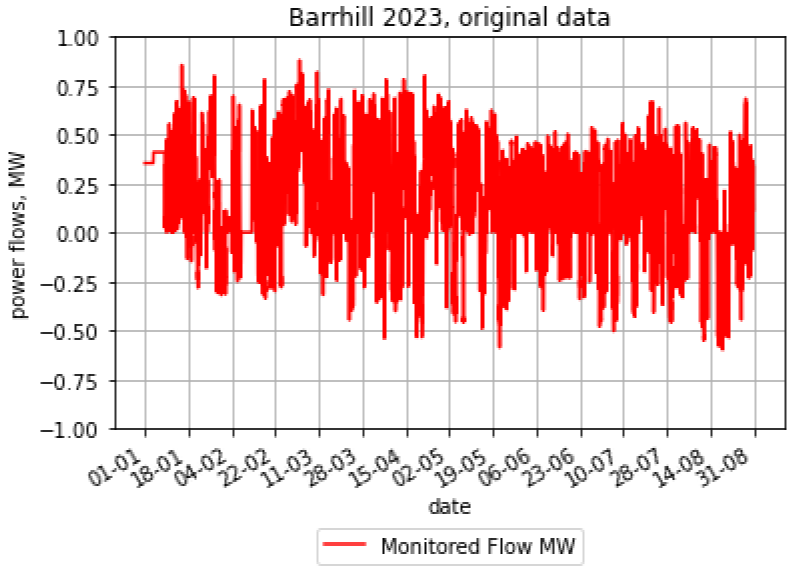


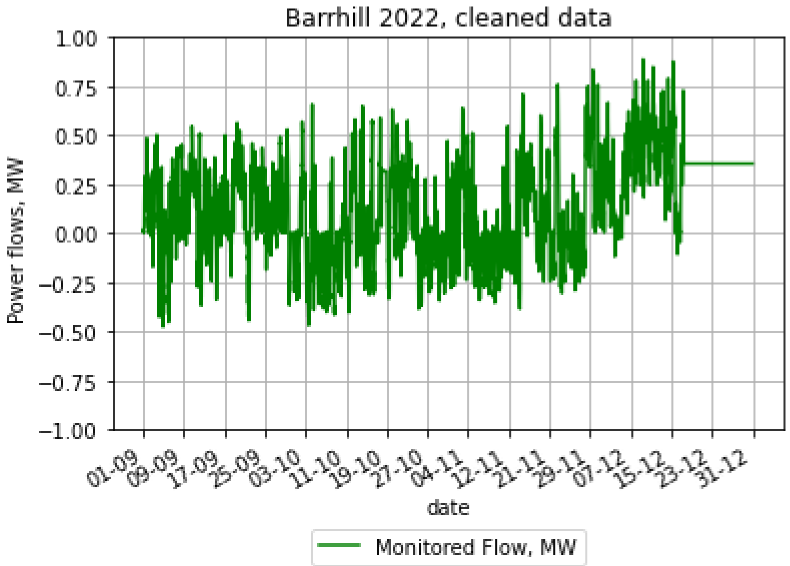


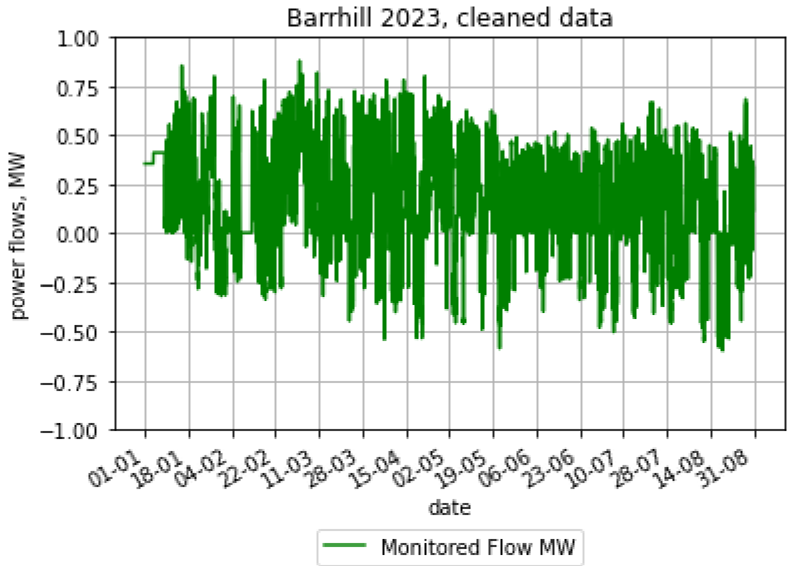


Barrhill “Monitored Flow” at11kV bus. Sept 2022 – Aug 2023, as downloaded, and after “cleaning”. This is the smaller contributor to Lochan Moor demand flows.

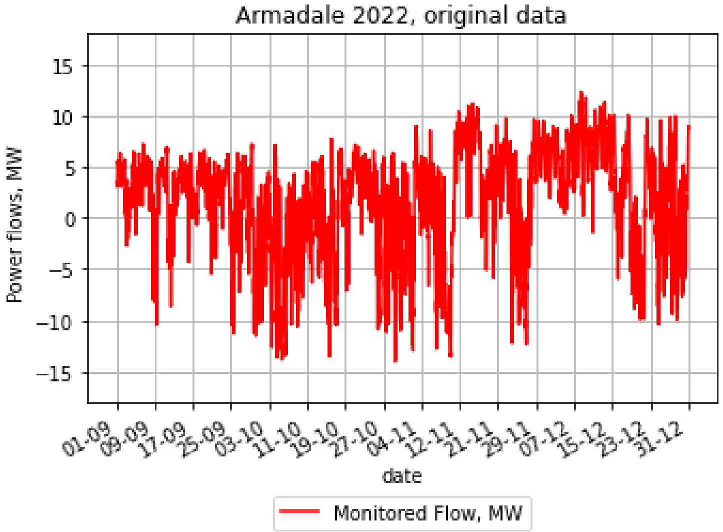


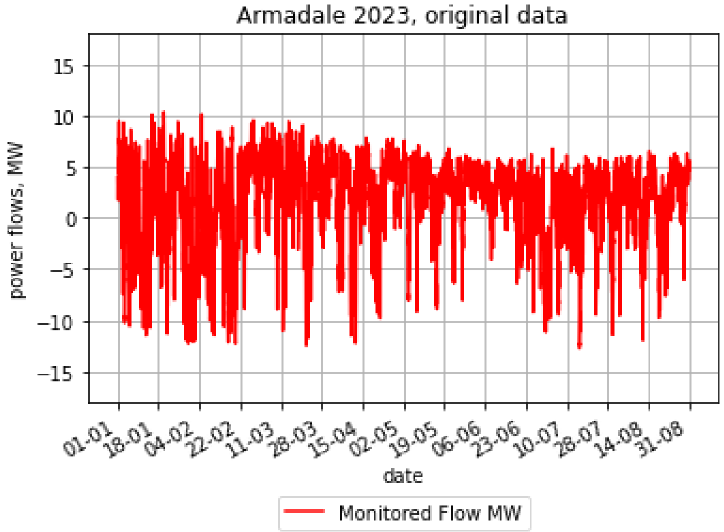


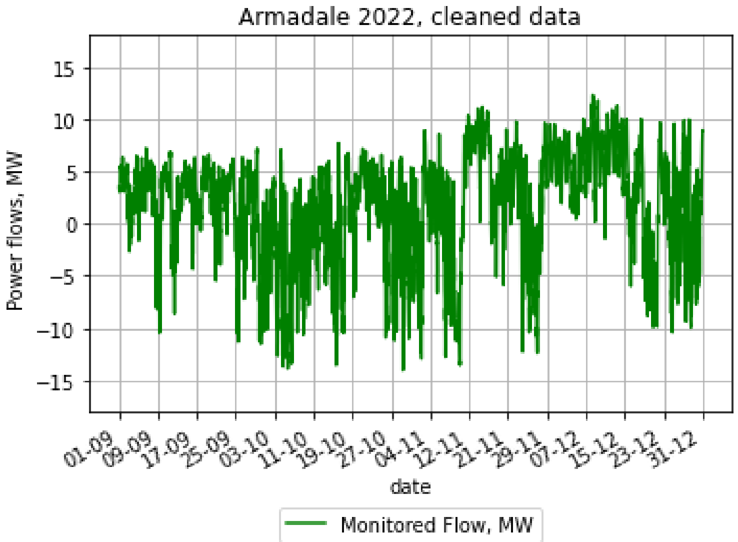


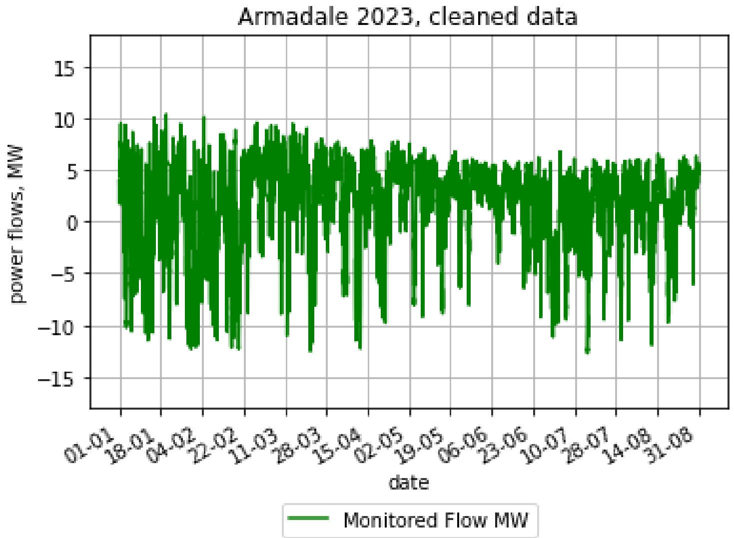


Armadale “Monitored Flow” at11kV bus. Sept 2022 – Aug 2023, as downloaded, and after “cleaning”. (This bus one shows a combination of wind generation – giving rise to negative flows, and demand.)

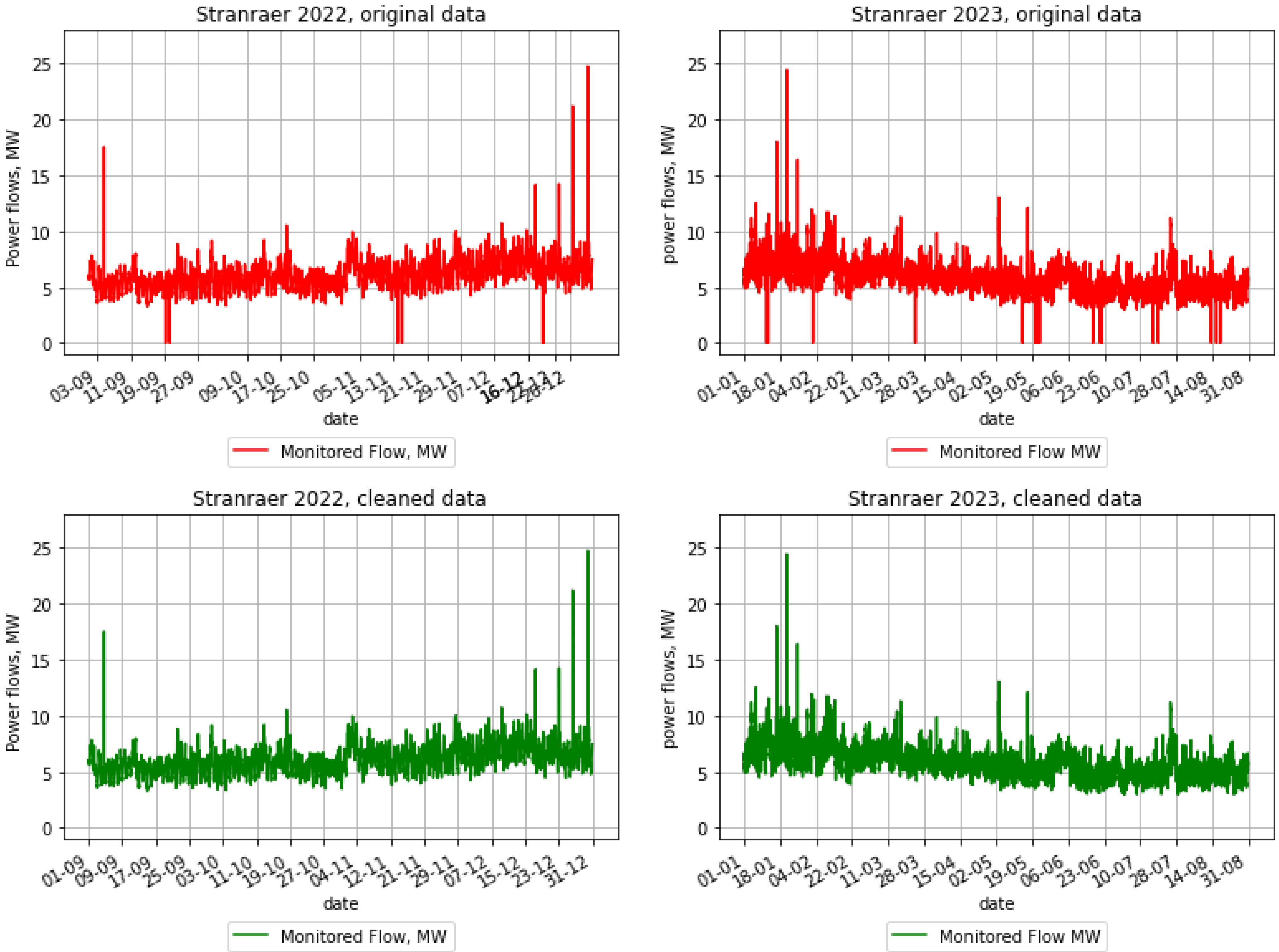




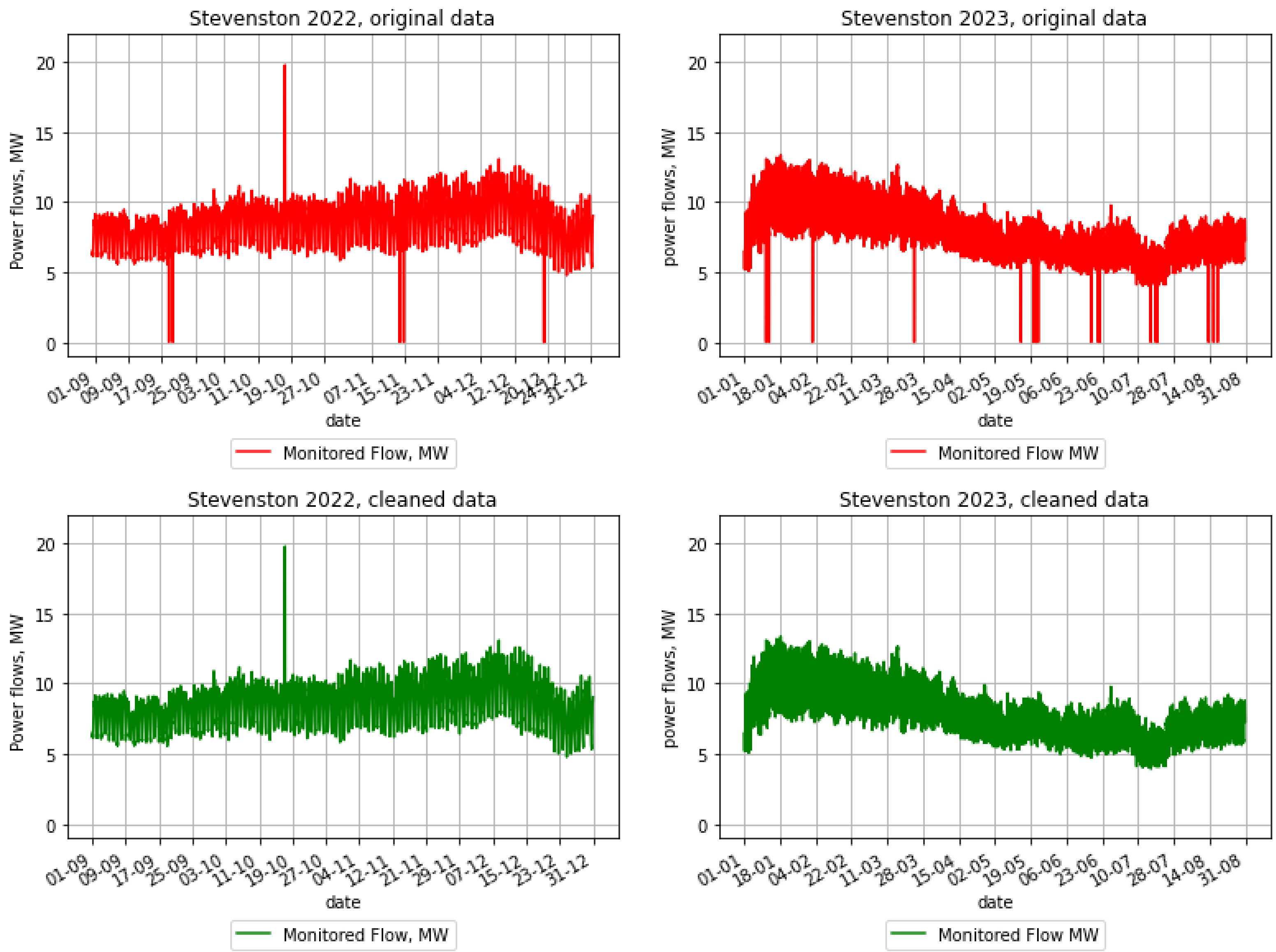




Stranraer “Monitored Flow” at11kV bus. Sept 2022 – Aug 2023, as downloaded, and after “cleaning”.



Stevenston “Monitored Flow” at11kV bus. Sept 2022 – Aug 2023, as downloaded, and after “cleaning”.



Chapter 6 Annex 4

Selection of SPEN datasets for use: for 11kV demand flows

SPEN's Open Data Portal lists two alternative datasets – "Monitored Flow (MW)" and "Demand (MW)", potentially either of which could be used. This annex describes the selection of "Monitored Flow", and gives further details about these datasets.

Armadale

Armadale is the only location with large 11kV-connected generation. Here, across the timeseries of data examined, the following equation applied at most times.

$$Demand\ (MW) \approx Monitored\ Flow\ (MW) - Generation\ (MW) \qquad (6.1)$$

Agreement was close but not exact at many timesteps. The DNO SPEN had indicated that the Open Data Portal data had had some noise introduced in order to "anonymise" data for reasons of data protection, and were in a format suitable for public sharing.

Flows at Armadale are later discussed in greater detail in Annex 7.

Locations other than Armadale

For the most of the other five case study locations, there is little or no difference between most values of "Monitored Flow" and "Demand" (abbreviated to "MF" and "Dem" on the following table).

However there are small discrepancies at both Lochan Moor (sum of flows at Auchneel and Barrhill 11kV buses) and at Largs.

Largs

At Largs there are discrepancies between Monitored Flow and Demand, of up to 0.6 MW.

SPEN's circuit diagram shows two small hydro generators connecting to Largs 11kV bus.

SPEN Open Data Portal listed "Generation (MW)" as follows, for all timesteps t (with "Generation < 0 "denoting an export power flow)

During 2022:

1 September – 31 December 2022 (including autumn and winter case study periods):

$$Generation_{Largs,t} = 0\ MW, \qquad for\ all\ values\ of\ t \qquad (A6.1)$$

During 2023:

1 Jan – 31 May:

$$Generation_{Largs,t} = -1\ MW, \quad for\ all\ values\ of\ t \qquad (A6.2)$$

1 June – 30 September:

$$Generation_{Largs,t} = 0\ MW, \qquad for\ all\ values\ of\ t \qquad (A6.3)$$

The apparent step changes in generation from 0 to 1 MW and back to zero occurred at midnight clock time, and were not accompanied by a step change in any other metrics. It is surmised that these generation output data may be estimates rather than measurements, and there may be in fact around 0.5 MW of flow from the hydro stations at times of discrepancy between “MF” and “Demand”. It was decided to use the figures for “Monitored Flow”, presumed to be a reading, rather than “Demand”, presumed to be synthesised from the reading and assumed generation. The Monitored Flow is thus “Demand net of any hydro (and any other) generation”.

Lochan Moor

At Lochan Moor there is a small discrepancy between MF and demand values, of up to around 0.5 MW at times of lowest demand values.

There are also instances of small reverse power flows (negative demand flows) from Barrhill (at all seasons) and Auchneel (during summer only), as shown in the previous Annex.

SPEN Open Data Portal listed “Generation (MW)”, at both the 11kV buses (Auchneel and Barrhill) which connect to Lochan Moor, as zero at all times.

$$Generation_{Auchneel,t} = Generation_{Barrhill,t} = \ 0\,MW, \qquad for\ all\ values\ of\ t \qquad \text{(A6.4)}$$

It is not clear why there are negative values of both demand and MF occur (illustrated in Chapter 6 Annex 3), suggesting net exports. No generators are listed by SPEN for either Auchneel or Barrhill, the two 11kV buses connecting into Lochan Moor 33 kV bus. Rooftop solar may contribute to exports, but some negative MF values (i.e. net exports) occurred at night. It is surmised that there may be some other very small DG on the network, as negative MF values (denoting exports) reach up to around 0.6 MW of export from the hamlet or farm of Barrhill, and up to around 0.1 MW of export from the village of Auchneel. SPEN’s ECR lists some connected microgeneration projects (< 1 MW output) in the area, but unfortunately without details of where they connect on the network. As in the case of Largs, the Monitored Flow values are also “Demand net of any micro DG”.

For consistency with other locations, Monitored Flow rather than Demand values are used.

Other locations

No other locations had instances of reverse power flows. If there was any microgeneration elsewhere it was smaller than the demand flows at all times. The close agreement of Demand and Monitored Flow data suggests that there were no other micro generators on the networks.

Chapter 6 Annex 5

Windfarms and proxy windfarms

Table 118 Windfarms and candidate proxy windfarms

Windfarm of interest	**Case study location**	**Candidate proxy windfarm**	**Transmission-(T) or Distribution-(D) connected**	**TEC / ECR capacity, MW** [214], [215]	**GSP** [229]	**MW by web site** [275], [276]	**2022 max output MW** [235]	**Individual turbine capacity** [222]	**Selection decision, and reason for exclusion**	**Distance km**
North Rhinns	Lochan Moor		D	22	Glenluce		-	2.0		-
		Kilgallioch	T	228	-	239	228	2.5	Selected	22
		Glen App	T	32.20	-		21	2.0	Rejected: Downtime in winter	15
		Glenchamber	D	27.50	Glenluce		13	2.5	Rejected: Low output in winter	23
		Airies	D	35.00	Newton Stewart		16	2.9	Rejected: Low output all year	29
		Arecleoch	T	114	-	120	110.88	2.0	Rejected: Downtime in winter	28
Kelburn A & B	Fairlie and Largs		D	14 (each)	Saltcoats B		-	2.0		-
		Whitelee	T	305	-		305	2.3	Selected	34
		Whitelee Extn	T	206	-		203	3.0	Rejected: Big turbines	34
Armadale windfarms	Armadale	Whitelee – summer only	T	305	-		305	2.3	Selected	45

The outputs of Kelburn A (Fairlie) and Kelburn B (Largs) windfarms are assumed to be identical.

Chapter 6 Annex 6

Timeseries of demand, generation and circuit flows, for each study location, during the three case study periods.

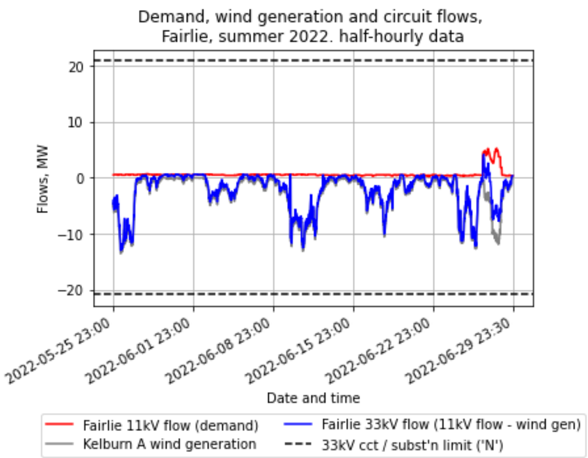
This annex shows how the base case circuit flows compare with the circuits' limits at 'N' security (all locations), and also, 'N – 1' (Armadale, Stranraer and Stevenston only).

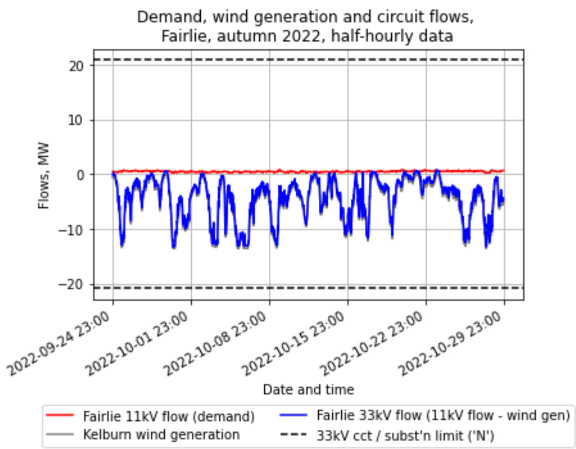
For autumn and winter 2022, all data are from 2022.

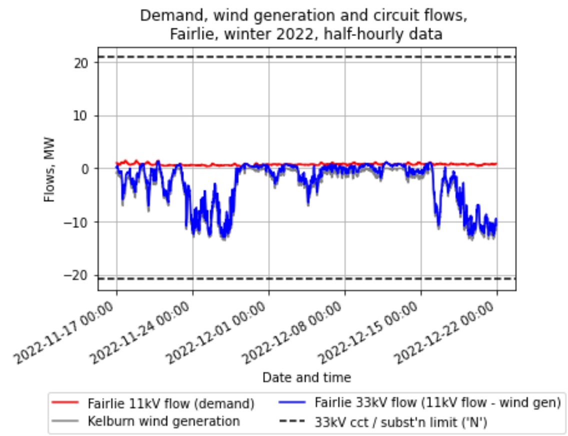
For summer 2022, the wind generation data are all from 2022. The SPEN data, describing 11kV network flows which are almost entirely demand flows, are for 2023. These datasets are used as a proxies for demands at each place, for the same time of year in 2022.

Armadale is exceptional in having SPEN data which describe both demand and generation. Annex 7 describes Armadale's data arrangements.

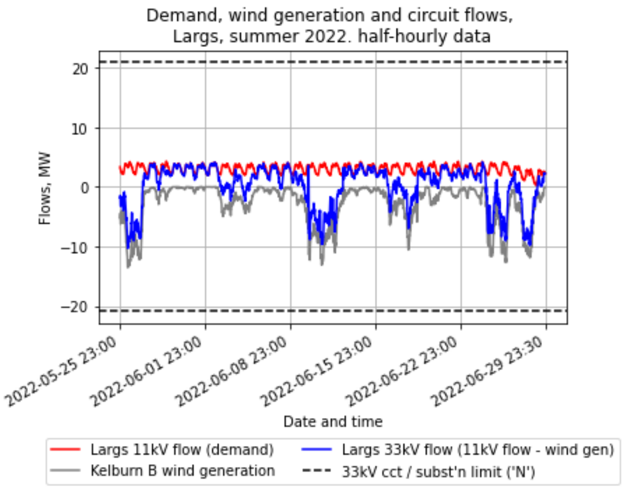
Fairlie:

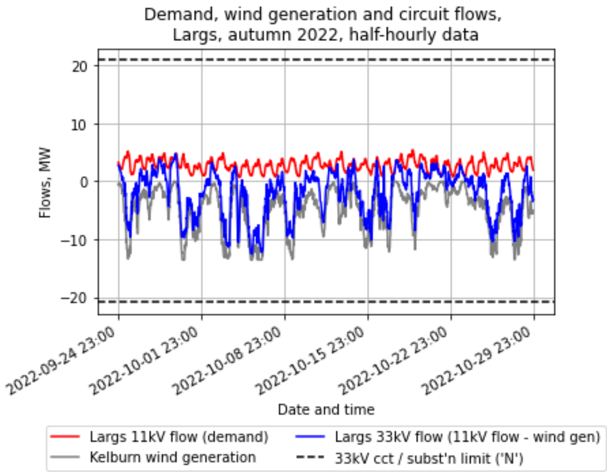


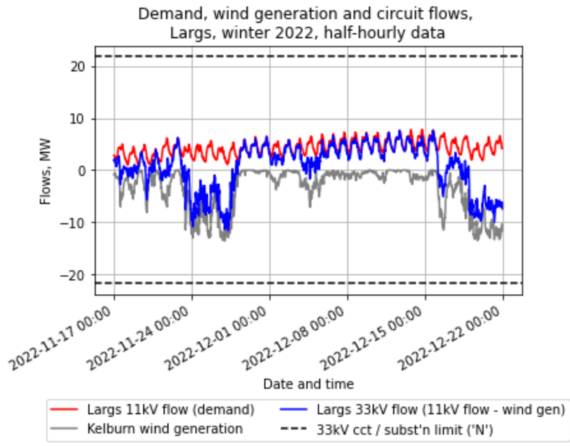




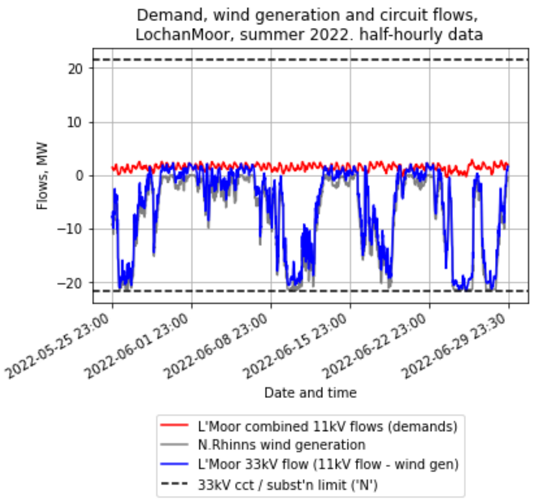
Largs

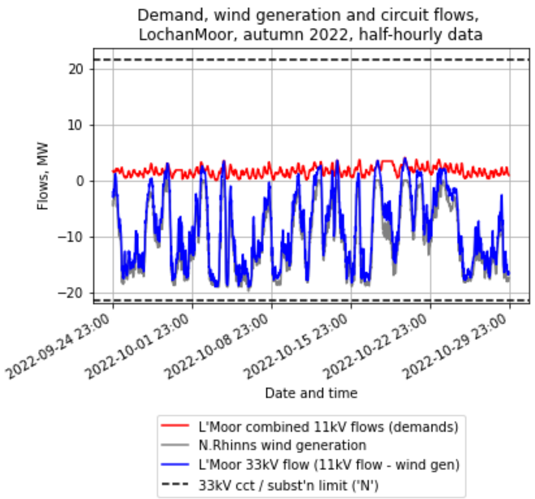


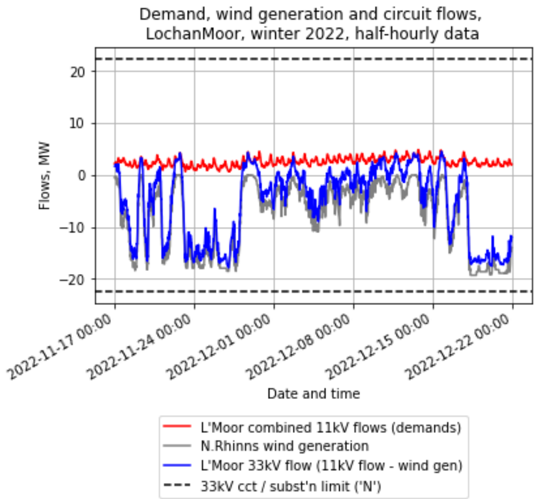




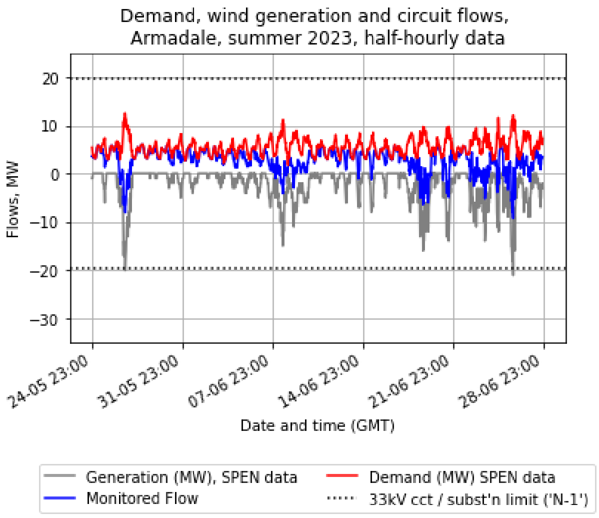
Lochan Moor

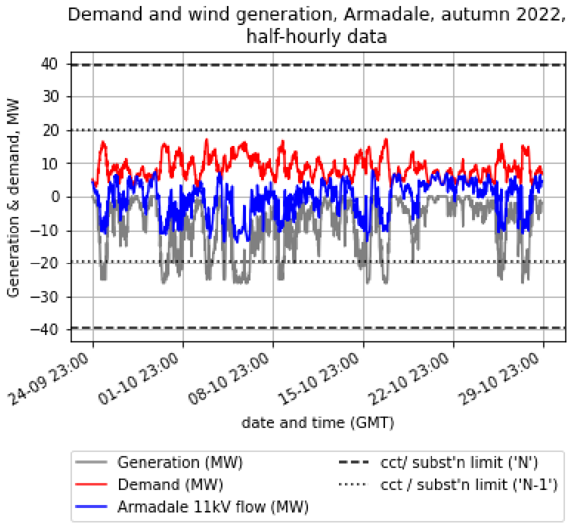


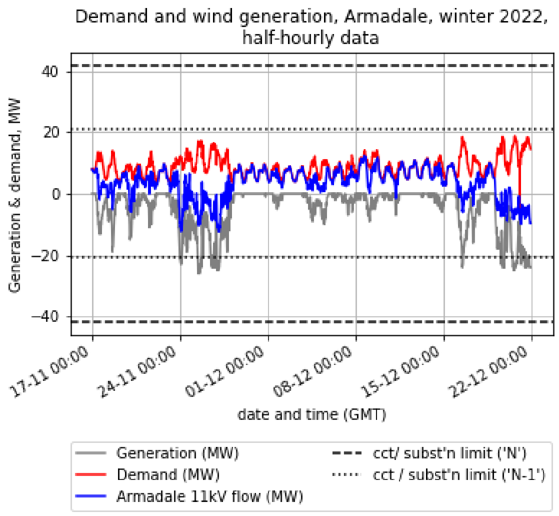




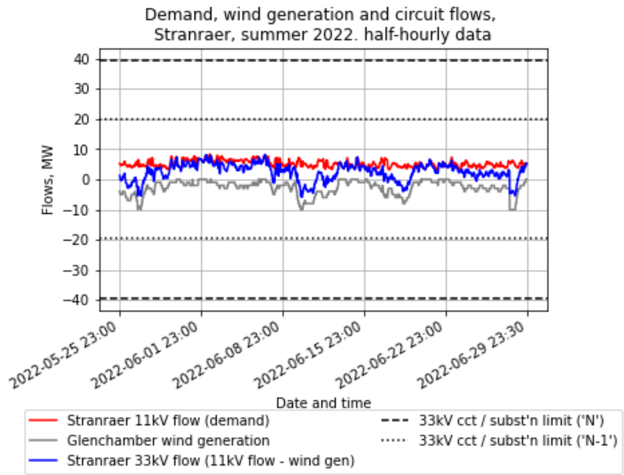
Armadale (Data as from SPEN, after cleaning *but not rescaling. Rescaling is described in Annex 7.*)

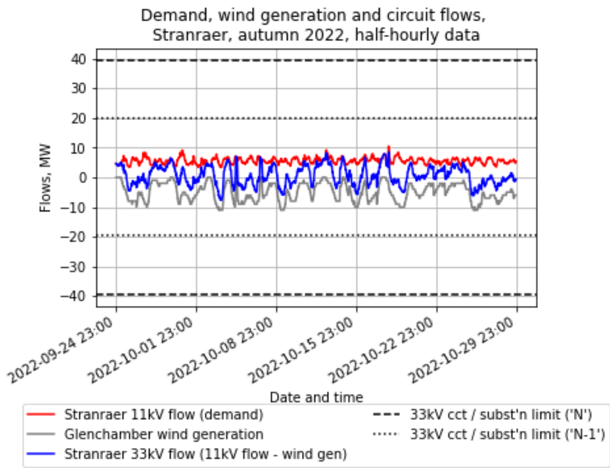


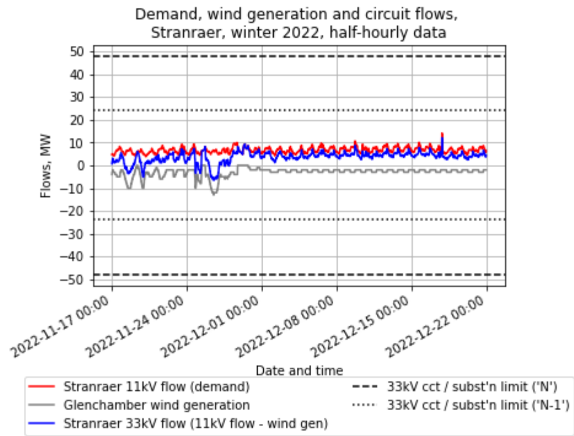




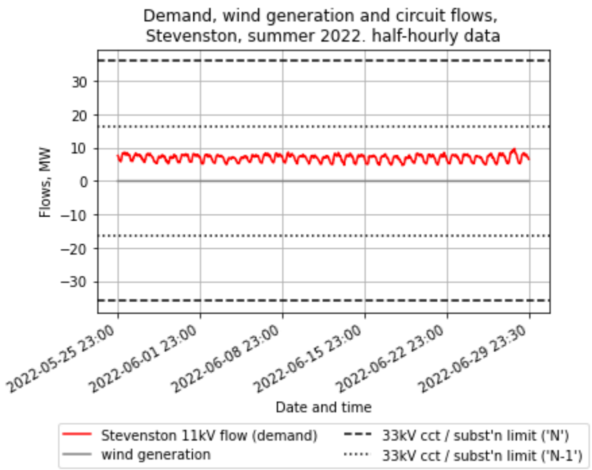
Stranraer:

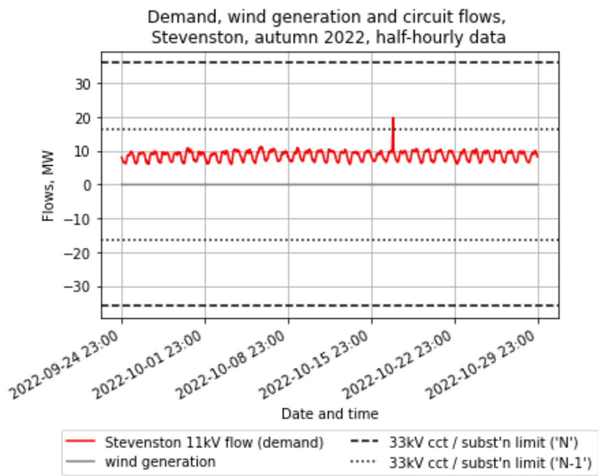


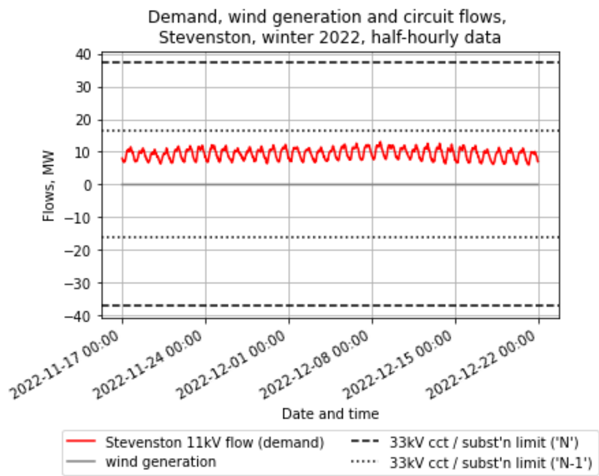




Stevenston:







Chapter 6 Annex 7

Armadale: rescaling generation and demand

Generation, Demand and Monitored Flow (all MW) as reported in SPEN's Open Data Portal, for Autumn, Winter and Summer case study periods

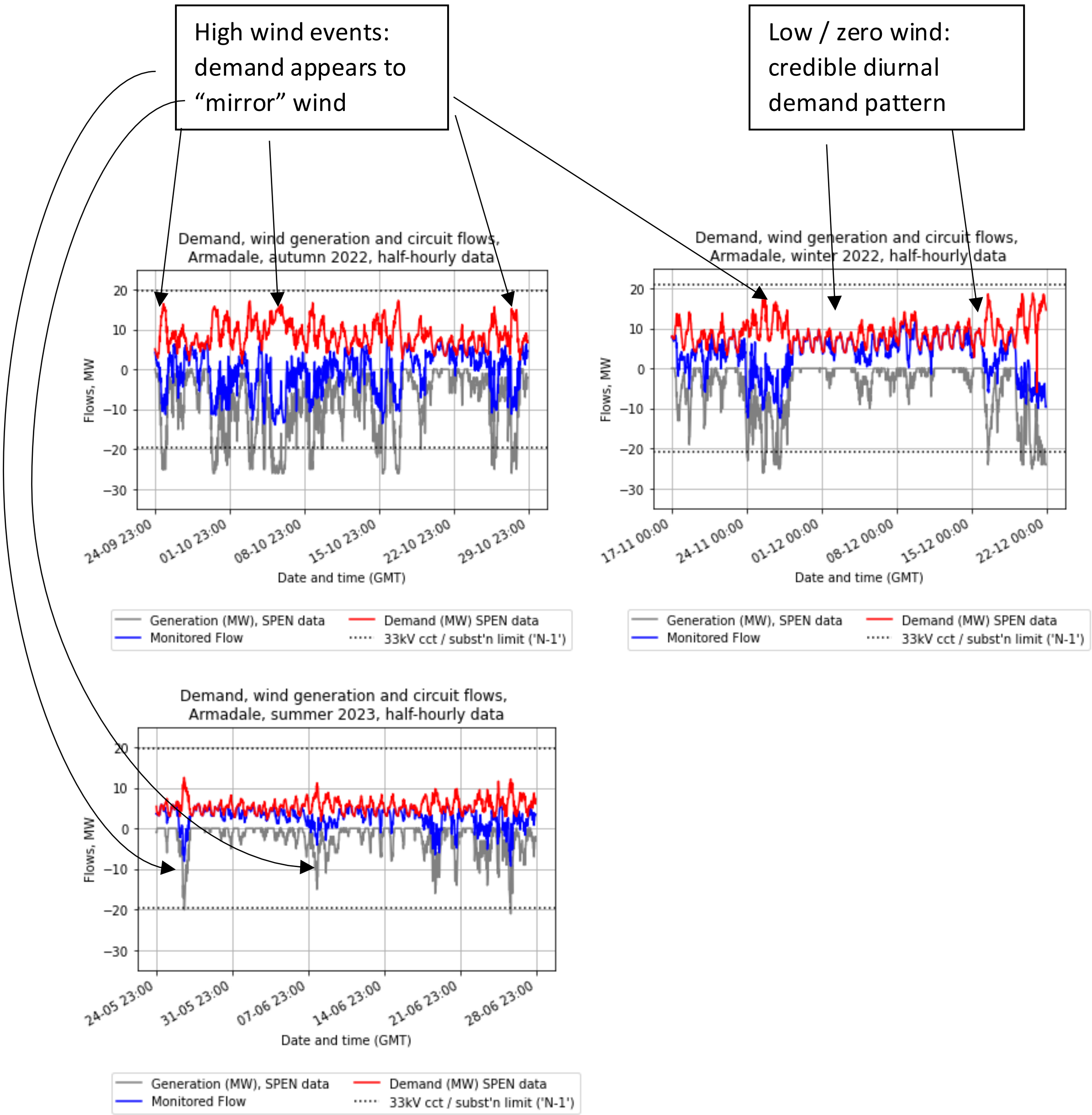


Figure 191 Armadale Demand, Generation and Monitored Flow, autumn and winter 2022, and summer 2023. SPEN Open Portal data.

The pattern of generation data is credible, being consistent with output from other windfarms examined in this study. The magnitude of output, however, up to 26 MW, is not credible, as the combined capacity of all four windfarms connecting at Armadale 11kV bus is 17.92 MW (SPEN's ECR and LTDS documents).

The pattern of demand data is not considered credible, other than at times of zero or very low wind output in winter and summer.

It was surmised that SPEN's demand data are derived from the monitored flows (assumed to be correct) and incorrectly scaled estimates of generation.

Demand data were recalculated, using various scaling factors from 40% to 80%, according to the equation below:

$Demand = Monitored\ Flow - Generation * scaling\ factor$ (where Generation values are all negative),

A scaling factor of 67% was considered to give the most credible demand profile, compared with demand profiles of Stevenston and Largs.

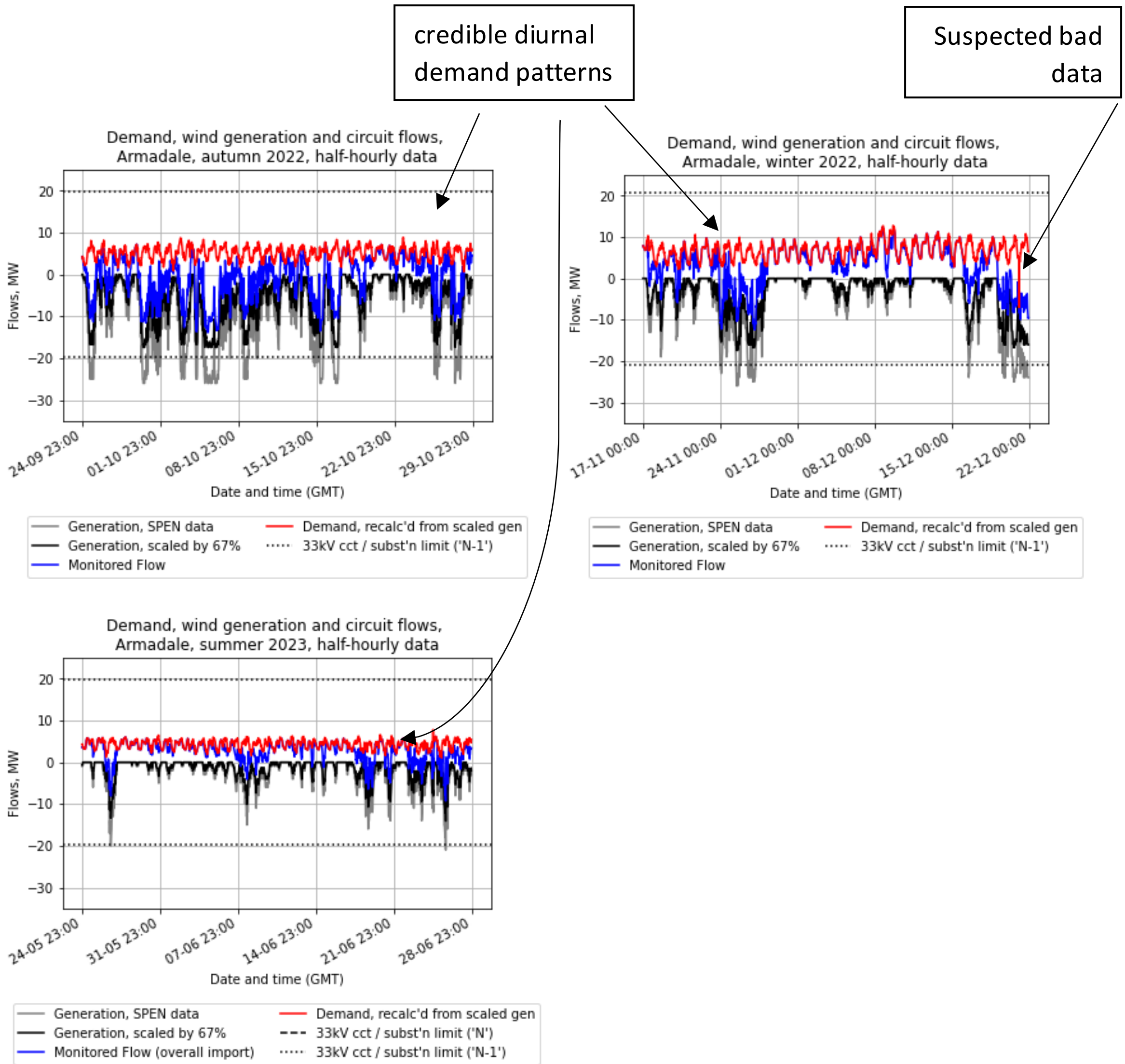


Figure 192 Armadale Demand, Generation and Monitored Flow, autumn and winter 2022, and summer 2023. Generation rescaled to 67% of SPEN value; demand recalculated from rescaled generation and Monitored Flow.

The maximum generation output, using this scaling factor, is 17.42 MW, which is 97% of the combined maximum capacity of all four windfarms connected at this bus. This value is also considered credible, based on (a) other embedded generators in SPEN's area[108]; and (b) the output from Whitelee Windfarm during 2022: It operated at a capacity factor (CF) of 1 during several occasions in January and February 2022. However, Whitelee's maximum output during the case study periods was 147.5 MWh/SP, compared to a 2022 max of 152.5MWh/SP, i.e. max CF during case study periods was 96.72%. If Armadale's windfarm's outputs correlated with Whitelee's FPNs, then they would be expected to operate with output of 17.91 MW during a few occasions in Jan and Feb 2022, outside of the case study periods.

Looking at the 2023 dataset and synthesising demands from monitored flows and rescaled generation: there are 15 values of demand that are negative, which are not considered credible. In all cases, there are negative Monitored Flow values and minimal or zero generation. Removing the lowest 20 values of rescaled demand, leaves a dataset in which all other values are credible. It is believed there is a temporal mismatch between actual outputs of Armadale windfarms and the generation figures reported by SPEN. The durations of these mismatches – around 10 hours over the year – are short, and do not fall within the summer case study period for which 2023 data are used.

There is one instance of a surprising and incredible value of recalculated demand in the 2022 dataset: a single negative value of synthetic demand, at 3am on 21 December. Half-hourly data display a sudden anomalous drop in generation from 03:00 to 03:30, with little accompanying change in Monitored Flow. As this occurred during one of the case study periods, it was considered a case of "bad data", suitable for "cleaning": the half-hourly generation figure was replaced by the average of the generation in the preceding and following SPs.

Monitored Flow values have not been changed and remain the basis for further calculations.

For summer, the rescaled demand for summer 2023 was used as a proxy for demand at Armadale during the same dates (adjusted by one day to reserve the day of the week) in 2022. These recalculated demand data were used in conjunction with scaled output from Whitelee windfarm from summer 2022, to estimate overall circuit flows during early summer 2022.

[108] 2022 data for onshore embedded wind generators in SPEN area, which participate in the BM, were examined. There were ten such generators. The 2022 highest Final Physical Notifications (FPNs) as a percentage of their stated capacity, are tabulated below.

	Maximum FPNs during 2022, as a % of stated capacity			
	100%	90% - < 100%	80% - < 90%	45% to 50%
Number of windfarms	4	3	1	2

Chapter 6 Annex 8

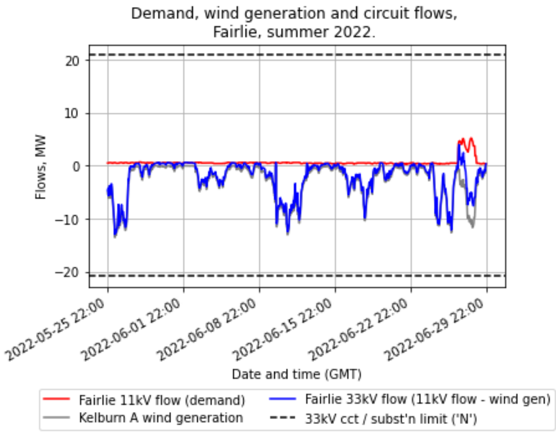
Base case (i.e. no battery) circuit flows during case study periods. Half-hourly data smoothed to hourly, and a 1-hour time shift introduced.

As stated in Chapter 6 Annex 6, the autumn and winter 2022 plots use entirely data from 2022 for the stated dates.

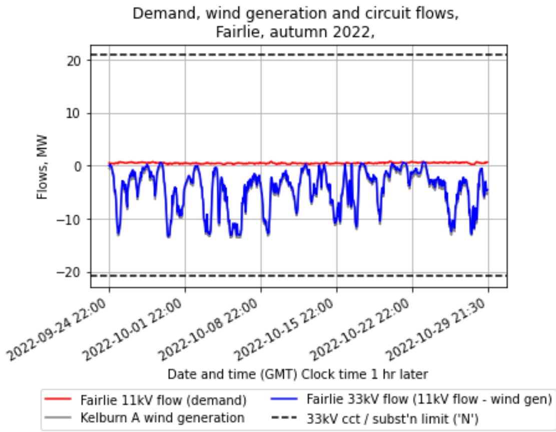
The summer 2022 plots have a combination of 2022 wind data, and “Monitored Flow” data (which is almost entirely demand dominated in all cases except Armadale) from 2023, which is used as a proxy for 2022 demand data.

The data are smoothed from half-hour to 1-hour resolution, in order to model together with battery simulated battery behaviour. The battery simulations have 1-hour timesteps because they are using a wholesale price dataset which has 1-hour resolution. Each “day” starts at 11pm UK clock time the day before the calendar date of the day, to align with the datasets for wholesale price data, which start at 11pm UK clock time the preceding day.

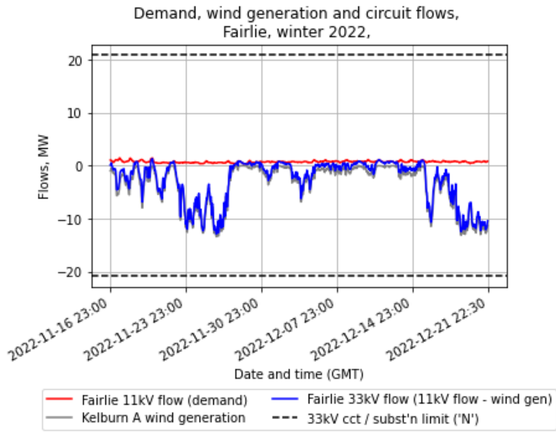
Fairlie and Largs:



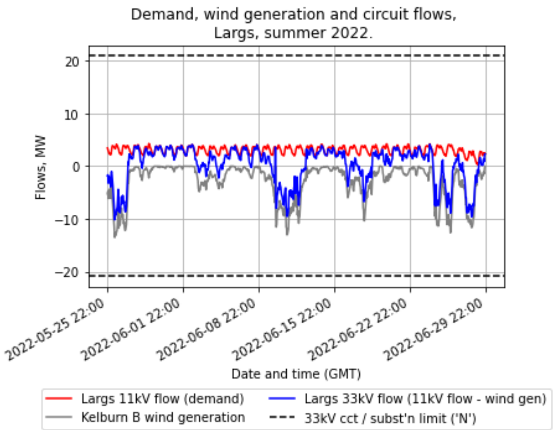
(a) Fairlie, Summer



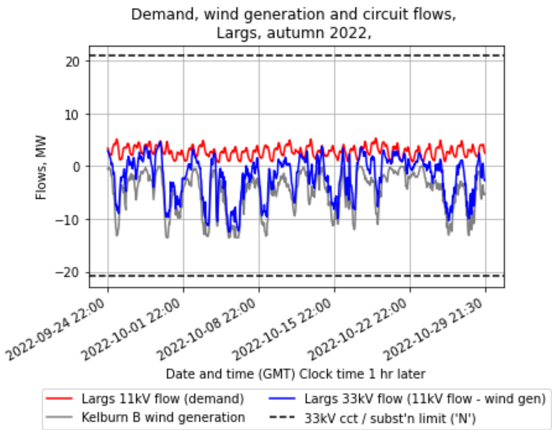
(b) Fairlie, Autumn



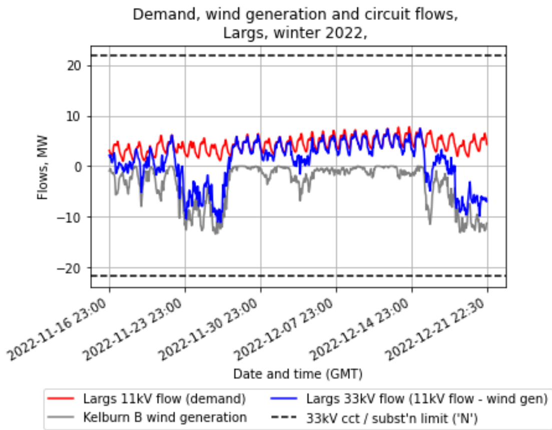
(c) Fairlie, Winter



(d) Largs, Summer

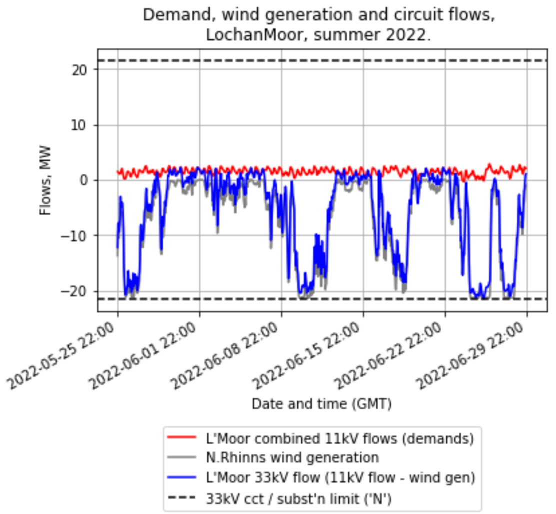


(e) Largs, Autumn

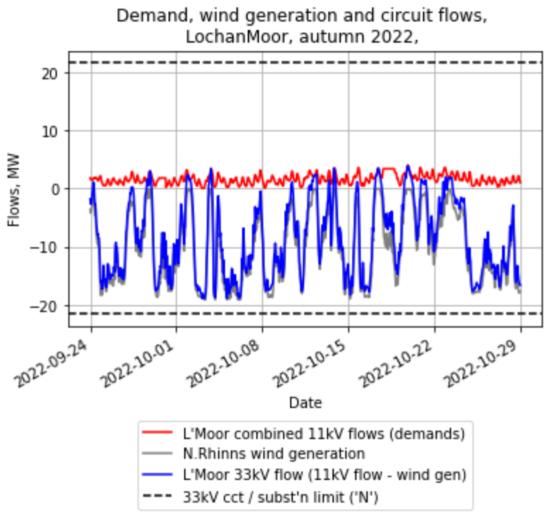


(f) Largs, Winter

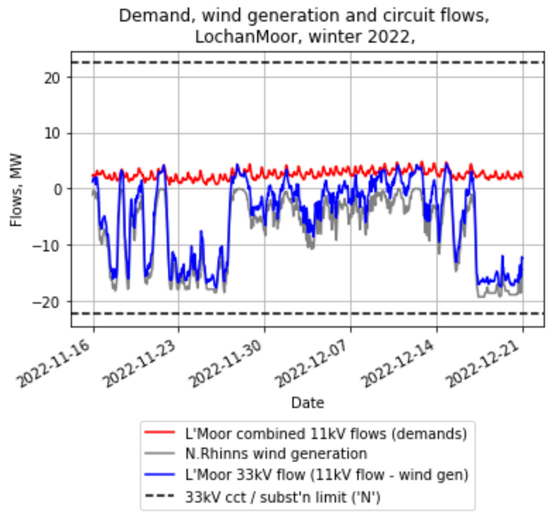
Lochan Moor



(a) Lochan Moor, Summer

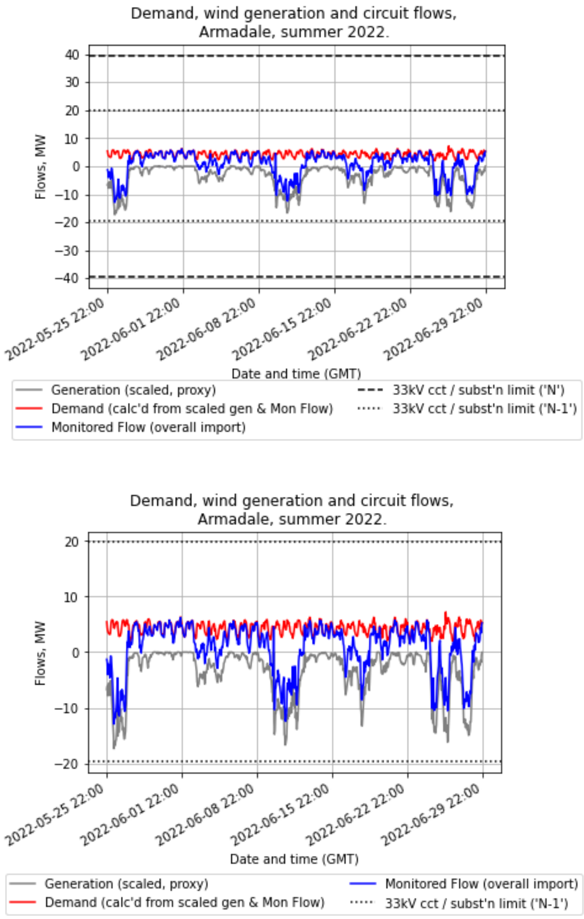


(b) Lochan Moor, Autumn

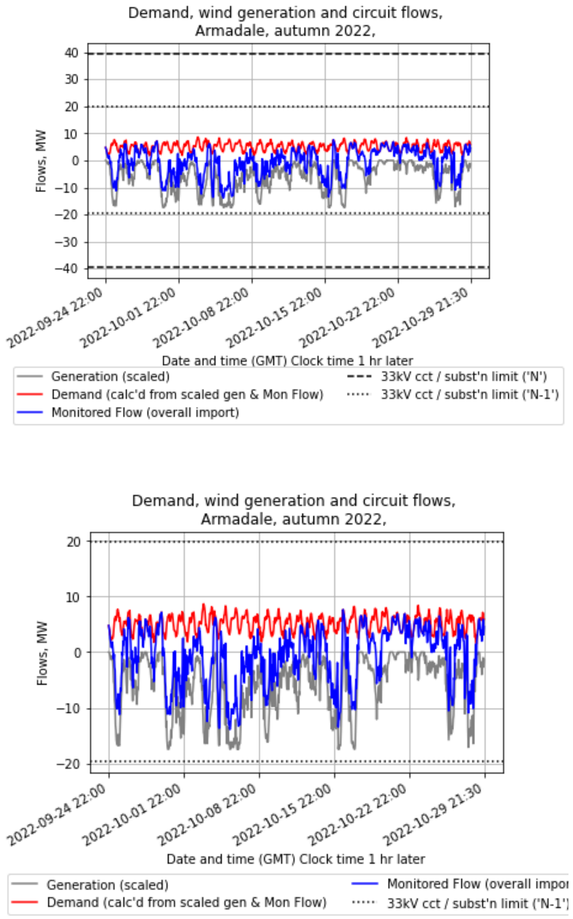


(c) Lochan Moor, Winter

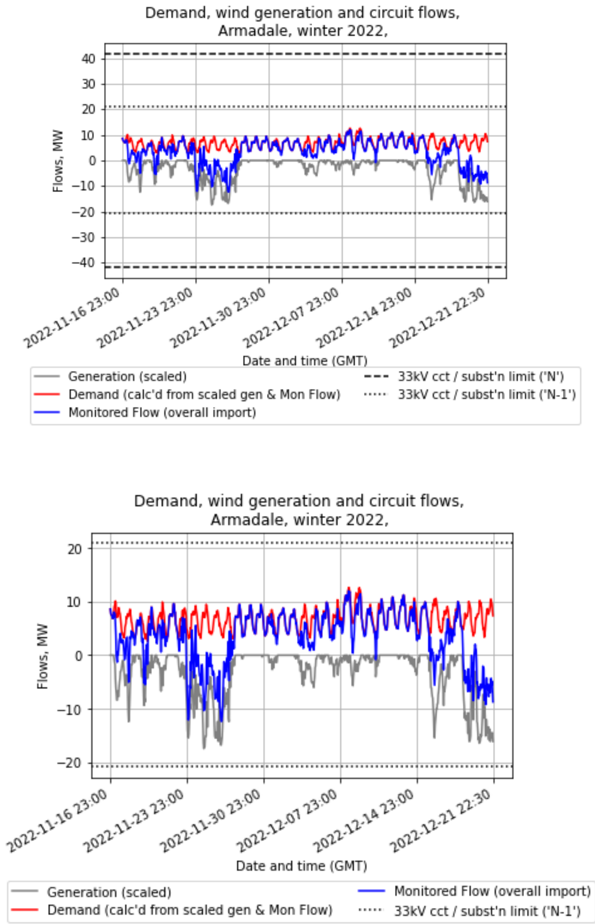
Armadale (rescaled). Scaled to show ‘N’ and ‘N-1’ circuit capacities



(a) Armadale, Summer

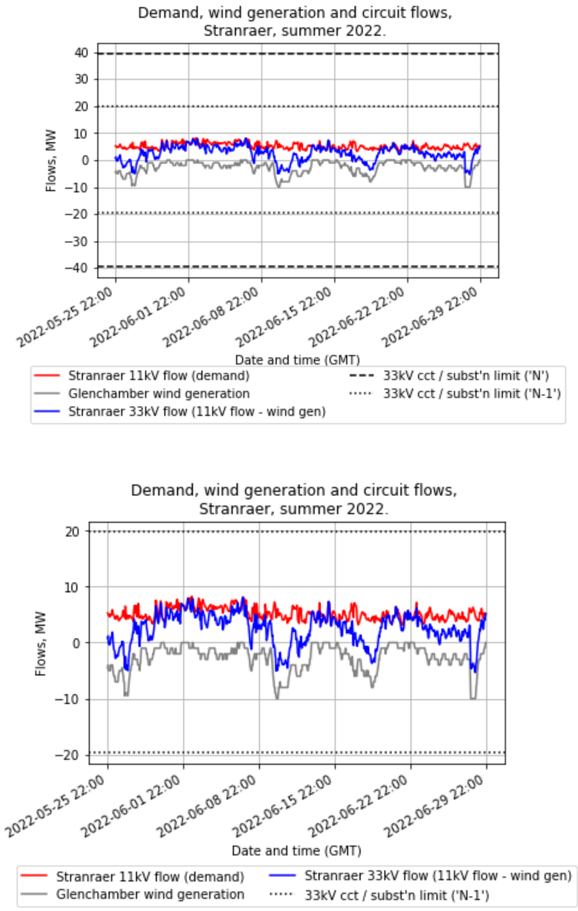


(b) Armadale, Autumn

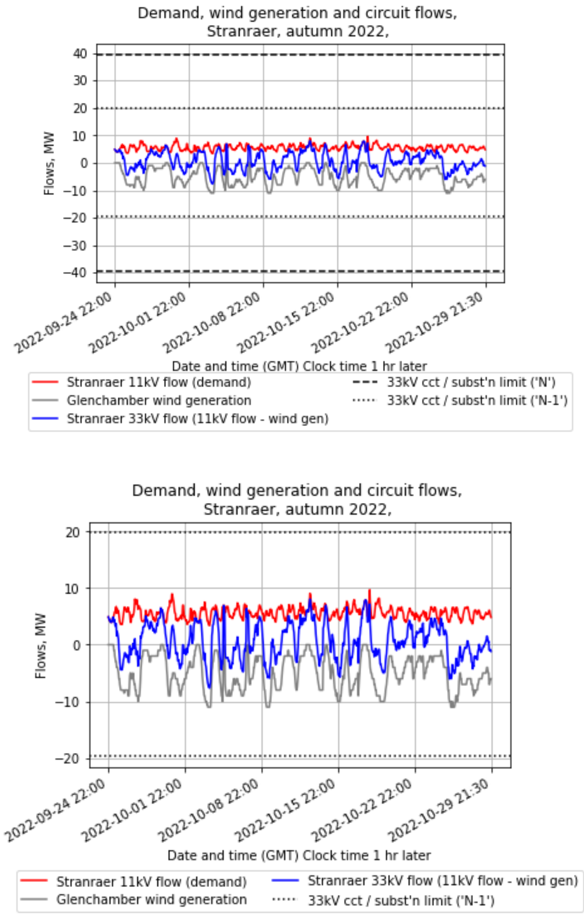


(c) Armadale, Winter

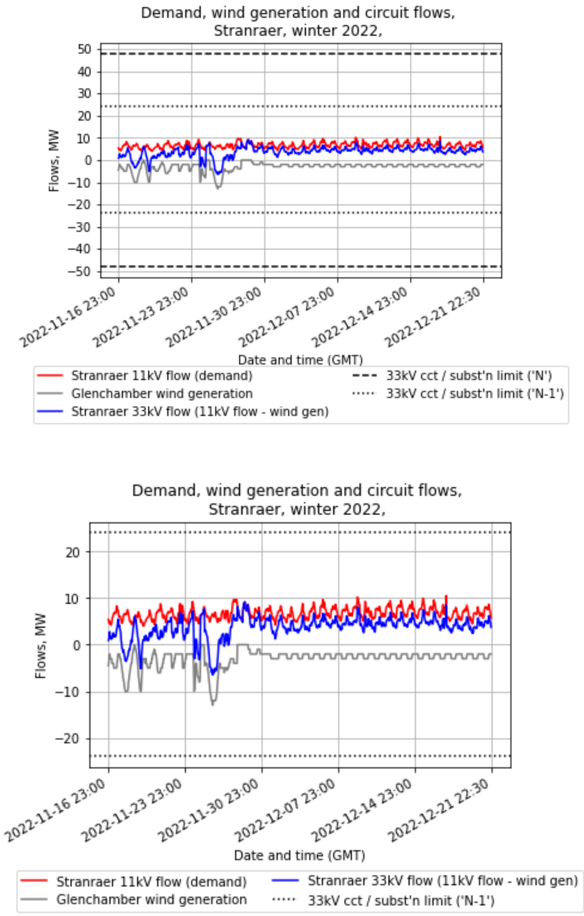
Stranraer. Scaled to show 'N' and 'N-1' circuit capacities



(a) Stranraer, Summer

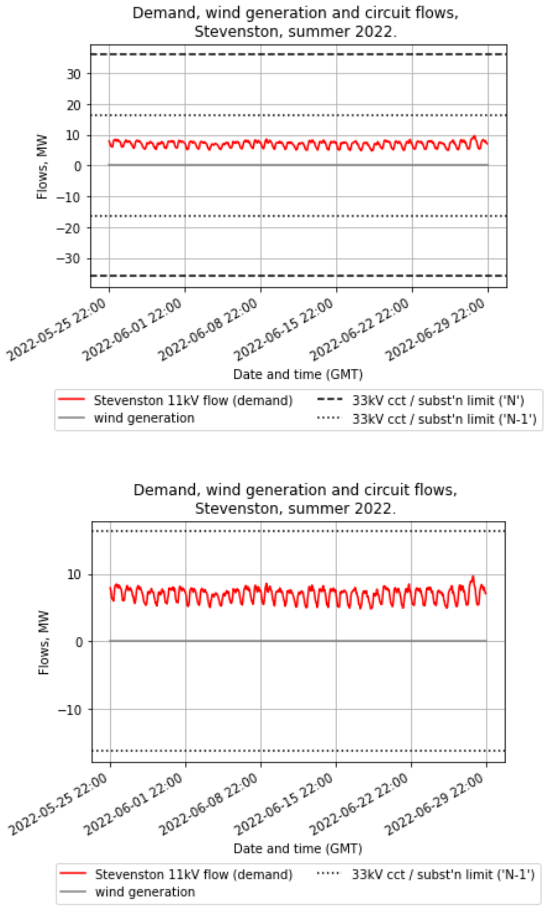


(b) Stranraer, Autumn

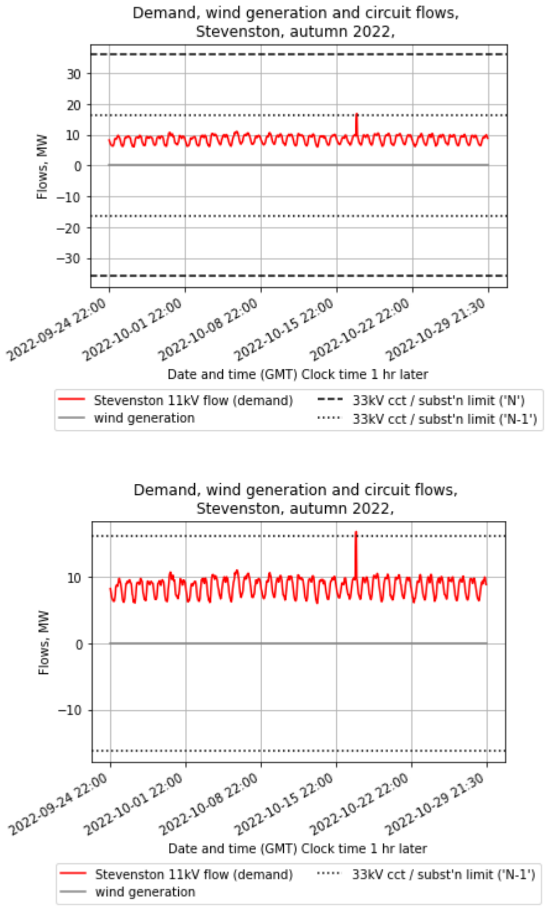


(c) Stranraer, Winter

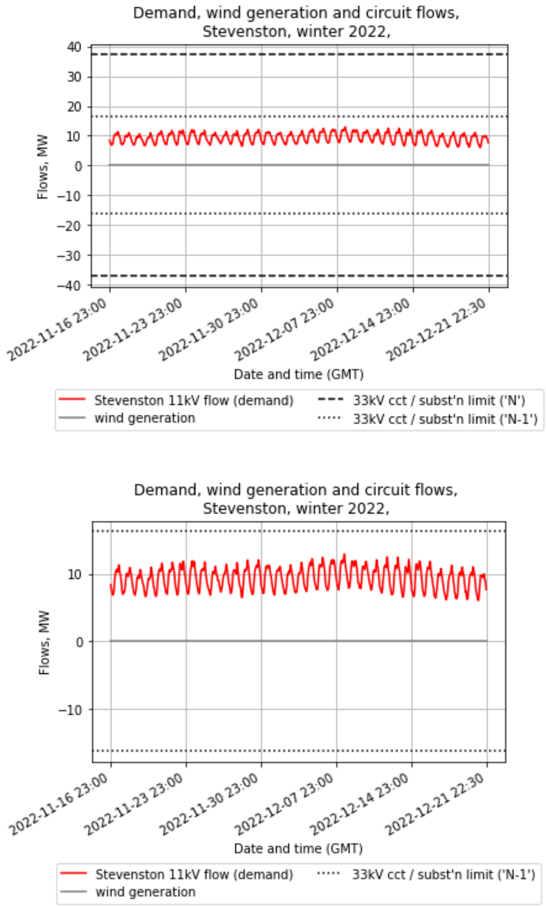
Stevenston. Scaled to show 'N' and 'N-1' circuit capacities



(a) Stevenston, Summer



(b) Stevenston, Autumn



(c) Stevenston, Winter

Chapter 6 Annex 9

Battery scaling used in modelling of aggregate circuit flows (Battery sizing: “Part 1”)

Table 119 Battery scalings used for modelling of combined flows on local networks

Case study location	**Circuit loadings**	**No. ccts. to GSP**	**Max / Min 2022 generation** [109]	**11 KV bus readings , 2022**		**Battery scaled capacity**					
				Max “Demand”	**Max / Min “Monitored Flow”** [110]	**Scale 1**	**Scale 2**	**Scale 3**	**Scale 3**	**Scale 4**	**Scale 5**
				excepting abnormal events					**Max generation**	**Max Demand**	**Variation in Demand**
			MW, hour-averaged								
Fairlie	Demand & wind	1	14 / 0	1.495	1.495	5	20	-	Summer: 13.5 Autumn: 13.5 Winter: 13.4	-	-
Largs	Demand & wind	1	14 / 0	8.362	7.805	5	20	-	As for Fairlie	Summer: 5.3 Autumn: 5.9 Winter: 8.3	Summer: 4.5 Autumn: 6.8 Winter: 4.6
Lochan Moor	Demand & wind	1	22 / 0	5.002	4.889	5	20	-	Summer: 21.3 Autumn: 19.1 Winter: 19.3	Summer: 3.1 Autumn: 4.1 Winter: 4.9	Summer: 2.8 Autumn: 3.5 Winter: 3.7
Stranraer	Demand & wind	2 [111]	13 / 0	*12.108*	*12.108*	5	20	40	Summer: 10.0 Autumn: 11.0 Winter: 13.0	Summer: 8.3 Autumn: 9.7 Winter: 10.5	Summer: 5.1 Autumn: 6.3 Winter: 6.5
Stevenston	Demand	2	0 / 0	12.78	12.78	5	20	40	-	Summer: 9.7 Autumn: 11.1 Winter: 13.0	Summer: 4.9 Autumn: 5.0 Winter: 6.9
Armadale (after re-calculating)	Demand & wind	2	17.91 / 0	13.408	12.01 import, 13.91 export	5	20	40	Summer: 17.3 Autumn: 17.4 Winter: 17.4	Summer: 7.2 Autumn 8.7 Winter: 12.6	Summer: 5.5 Autumn: 7.2 Winter: 10.0

[109] BM generation data: maximum values are for the whole of 2022. SPEN data portal, all metrics: “maximum 2022” values are for the period of available data, from 1 September – 31 December 2022 and 1 Jan – 31 Aug 2023.
[110] All max “Monitored Flows” are import / demand flows, unless otherwise stated (Armadale only)
[111] Glenchamber windfarm is attached to a 33kV bus on one of the circuits between Stranraer town and Glenluce GSP.

Chapter 6 Annex 10

Battery trading parameters

For batteries of different durations and round-trip efficiencies, the single "highest cashflow" scenario was used in all simulations of battery activity, as discussed in Chapter 4. Table 120 below shows these trading parameters, for batteries of different duration and round-trip efficiency

Table 120 Battery simulation: trading parameters used

Battery duration	Battery round-trip efficiency	Trading scenario used in battery simulations: trading strategy and visibility window		
		Summer	Autumn	Winter
2 hours	85%	"moderate", 3 hrs	"moderate", 3 hrs	"moderate", 3 hrs
2 hours	70%	"good price", 8hrs	"good price", 4 hrs	"best price", 5 hrs
4 hours	85%	"busy", 4 hrs	"busy", 4 hrs	"busy", 4 hrs
12 hours	85%	"busy", 10 hrs	"busy", 10 hrs	"busy", 9 hrs
12 hours	70%	"moderate", 21 hrs	"busy", 22 hrs	"busy", 9 hrs

As described in the thesis Chapter 6, Section 6.5.4, default initial SOC for batteries was 0.5, which was used in Autumn and Winter for all batteries.

For the summer runs, different initial SOCs were used, to avoid a significant price correction at the end of the run, due to the final wholesale price being unusually high compared with prices in the rest of the run. Thus, the initial SOC was chosen to be close to that at the end of the run, as shown in Table 121.

Table 121 Battery simulation: Initial State of Charge used

<table>
<tr><th rowspan="3">Battery duration, hours</th><th rowspan="3">Battery round trip efficiency</th><th colspan="3">Initial State of Charge of battery</th></tr>
<tr><th colspan="3">Case study season</th></tr>
<tr><th>Summer</th><th>Autumn</th><th>Winter</th></tr>
<tr><td>2</td><td>85%</td><td rowspan="3">0</td><td rowspan="5">0.5</td><td rowspan="5">0.5</td></tr>
<tr><td>2</td><td>70%</td></tr>
<tr><td>4</td><td>85%</td></tr>
<tr><td>12</td><td>85%</td><td>0.6667</td></tr>
<tr><td>12</td><td>70%</td><td>0.85</td></tr>
</table>

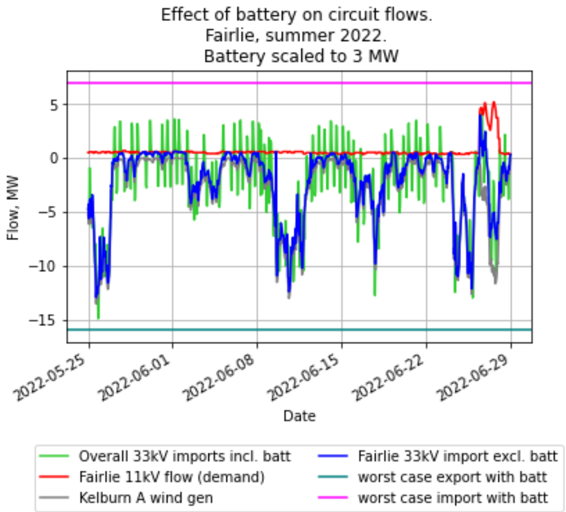
Chapter 6 Annex 11

Timeseries circuit flows with additional battery: 3 MW, 5 MW, 20 MW, and (for two-branch circuits only,) 40 MW

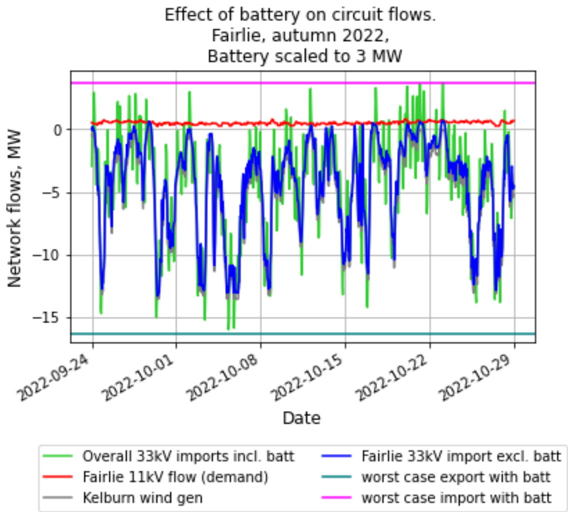
Note: all runs start at 11pm clock time

Annex 11A Battery scaled to 3 MW

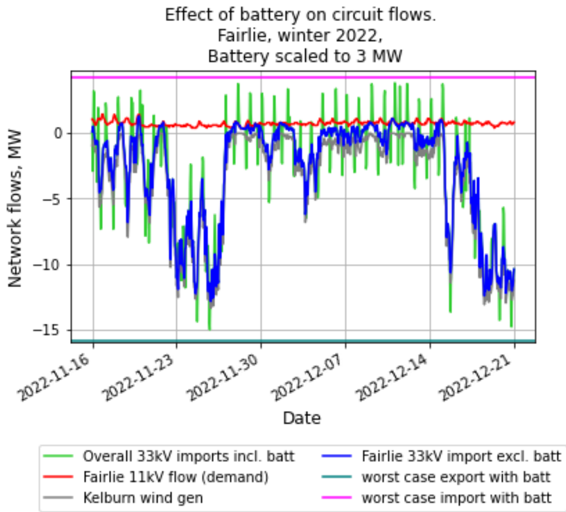
Annex 11A 1. Battery scaled to 3 MW: Fairlie



(a) Fairlie, Summer

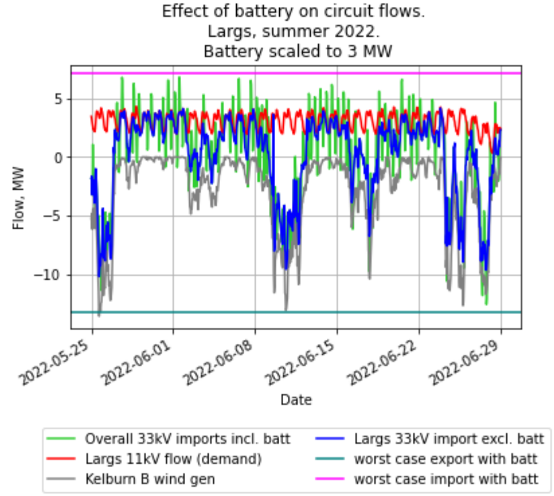


(b) Fairlie, Autumn

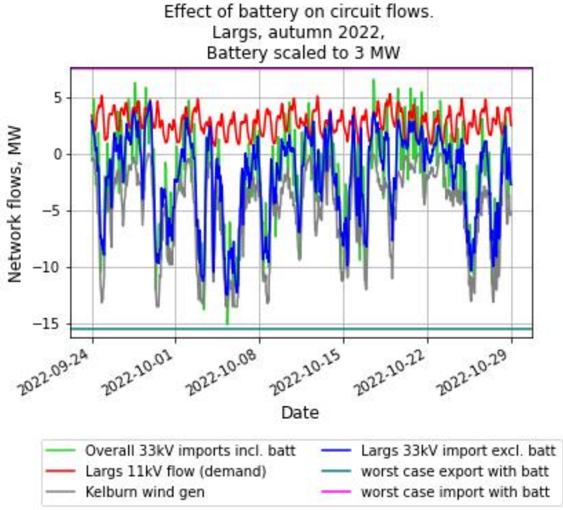


(c) Fairlie, Winter

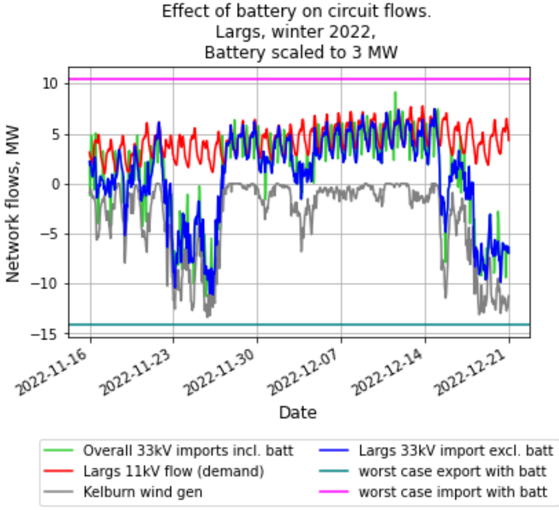
*Annex 11A 2. Battery scaled to 3 MW: **Largs and Lochan Moor***



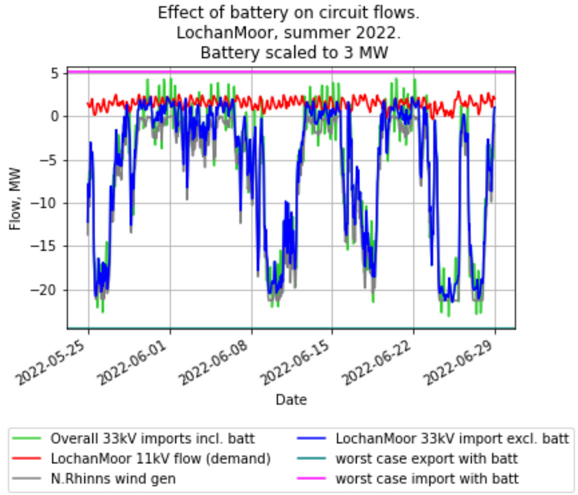
(a) Largs, Summer



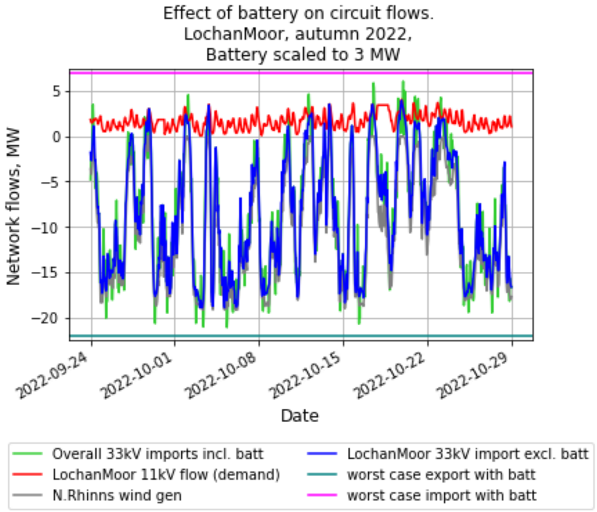
(b) Largs, Autumn



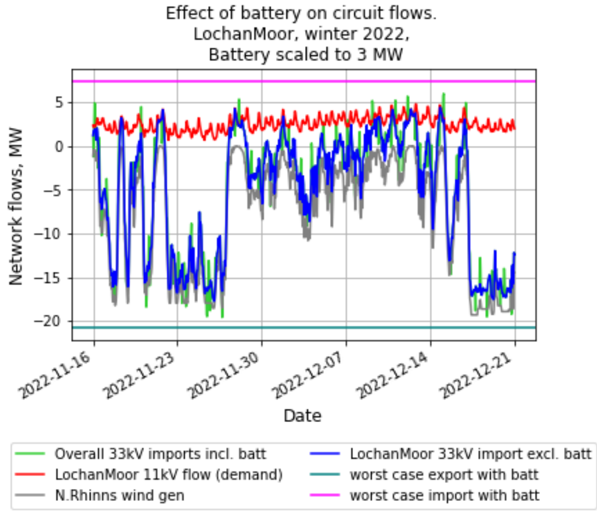
(c) Largs, Winter



(d) Lochan Moor, Summer

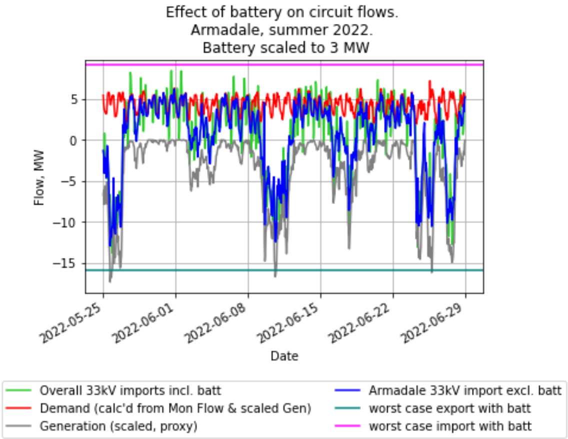


(e) Lochan Moor, Autumn

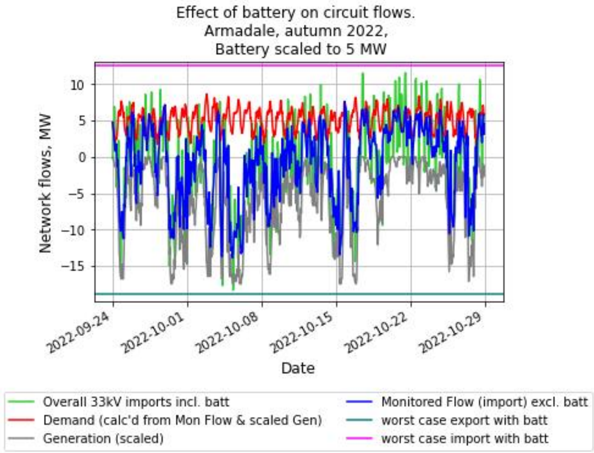


(f) Lochan Moor, Winter

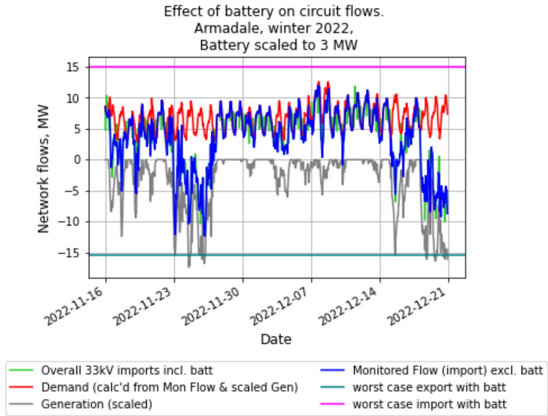
*Annex 11A 3. Battery scaled to 3 MW: **Armadale and Stranraer***



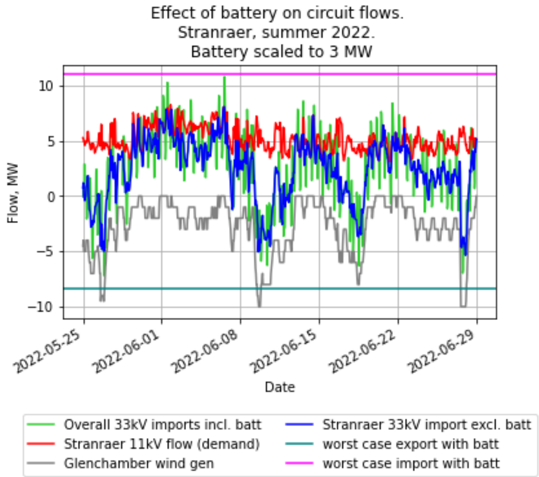
(a) Armadale, Summer



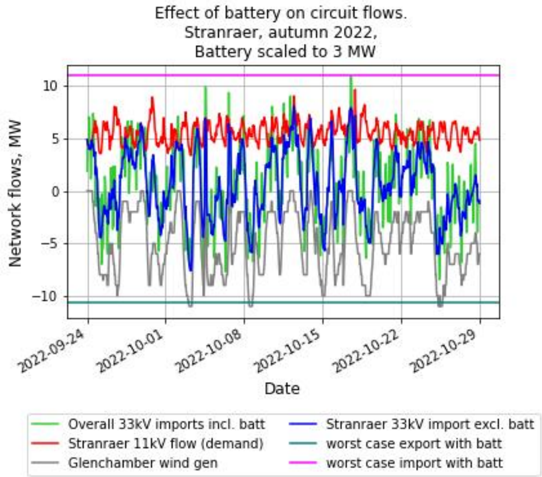
(b) Armadale, Autumn



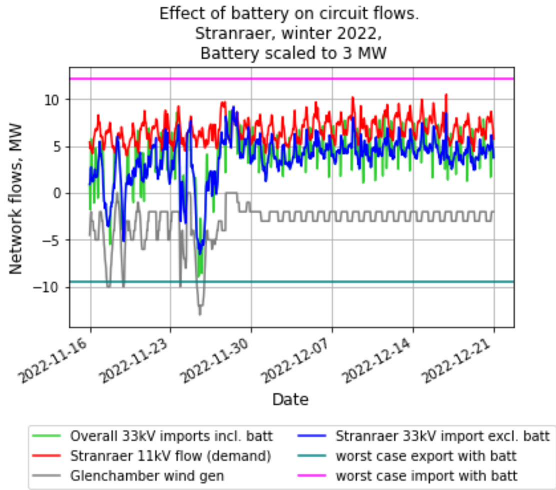
(c) Armadale, Winter



(d) Stranraer, Summer

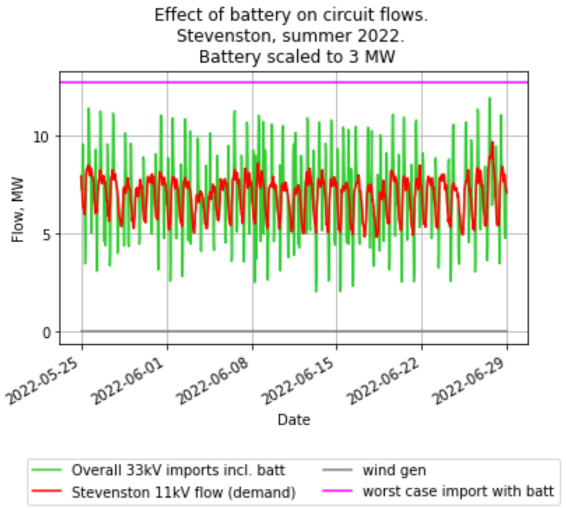


(e) Stranraer, Autumn

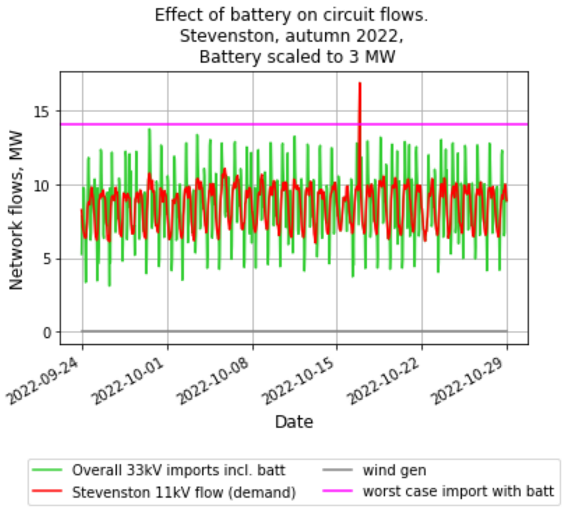


(f) Stranraer, Winter

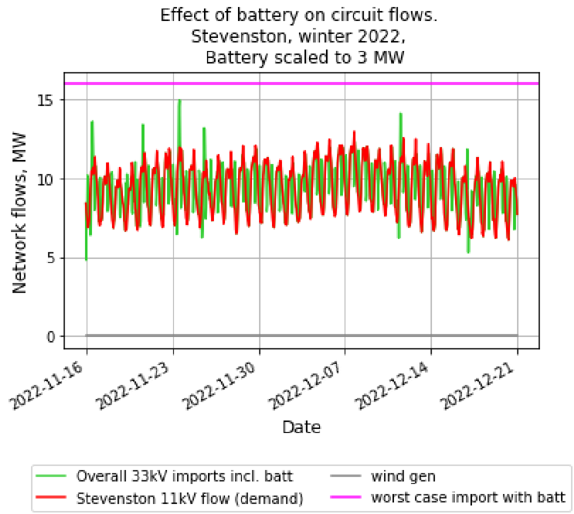
Annex 11A 4. Battery scaled to 3 MW: Stevenston



(a) Stevenston, Summer



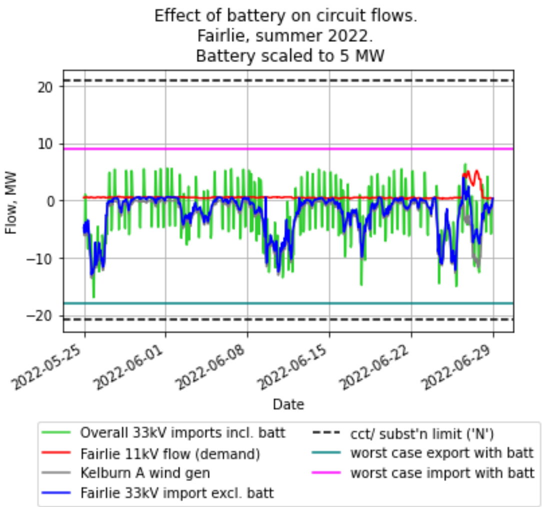
(b) Stevenston, Autumn



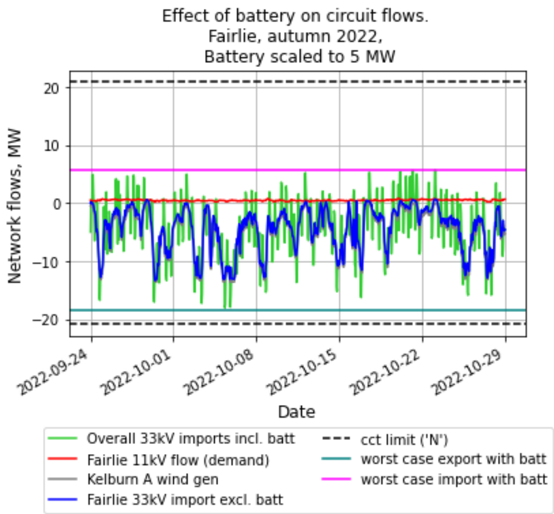
(c) Stevenston, Winter

Annex 11B Battery scaled to 5 MW

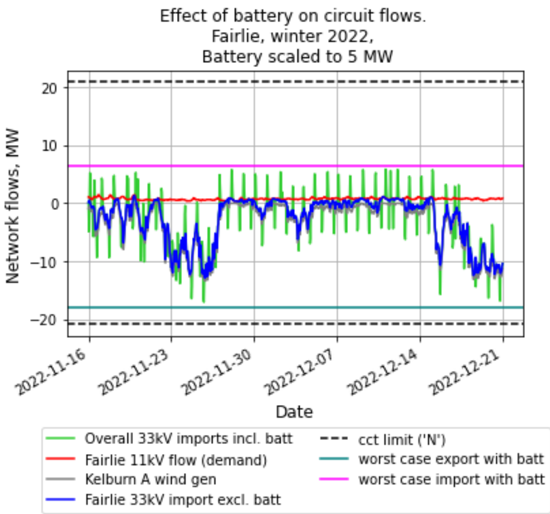
*Annex 11B 1. Battery scaled to 5 MW: **Fairlie,** showing 'N' circuit limits*



(a) Fairlie, Summer

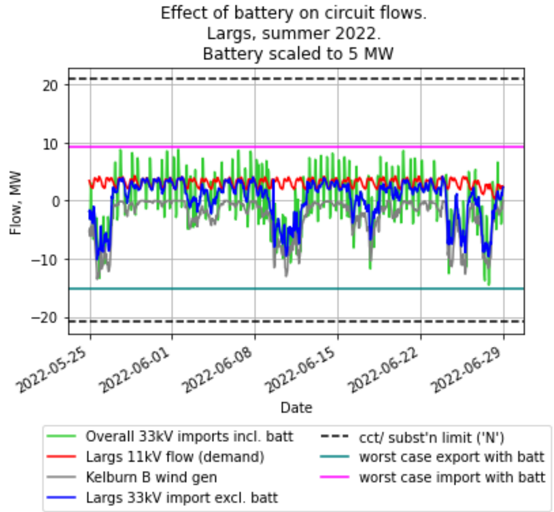


(b) Fairlie, Autumn

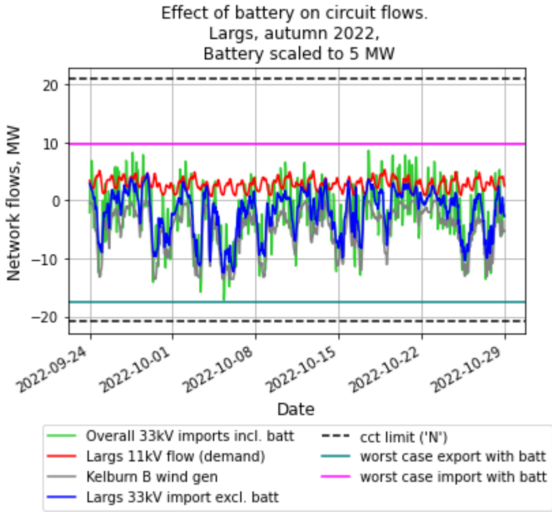


(c) Fairlie, Winter

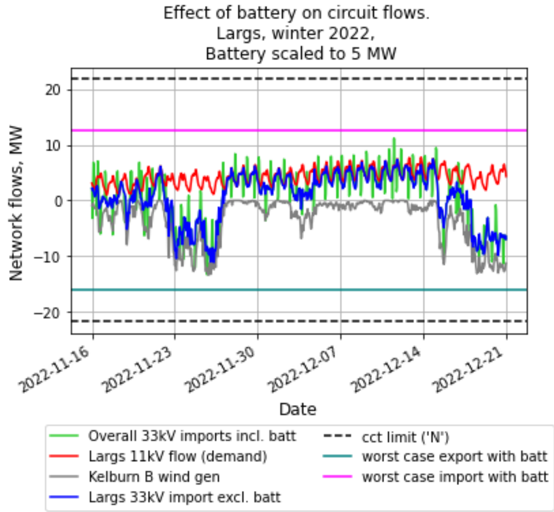
*Annex 11B 2. Battery scaled to 5 MW: **Largs and Lochan Moor** showing 'N' circuit limits*



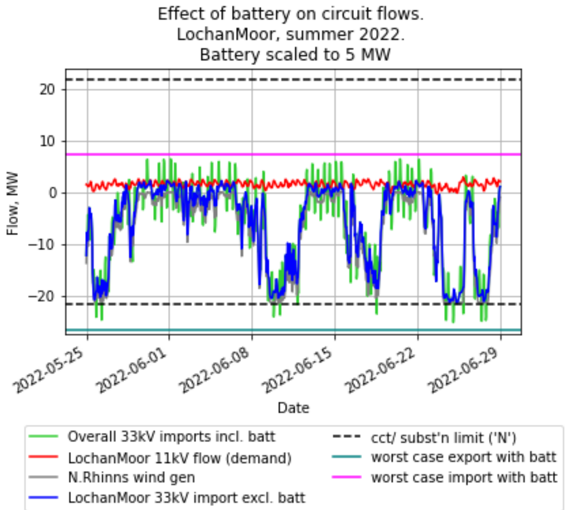
(a) Largs, Summer



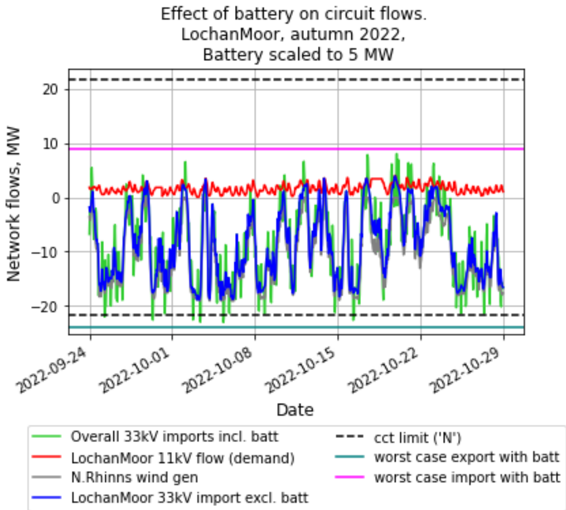
(b) Largs, Autumn



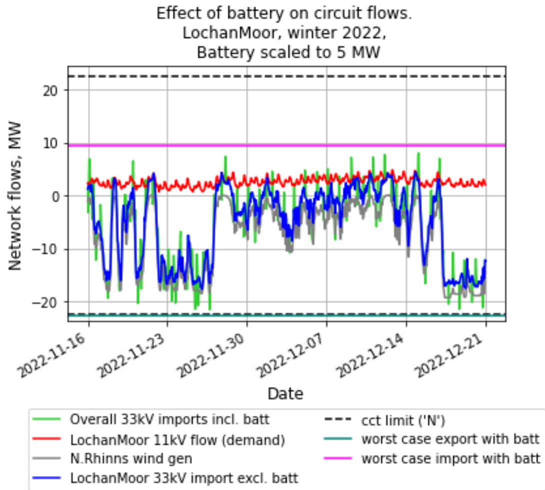
(c) Largs, Winter



(d) Lochan Moor, Summer

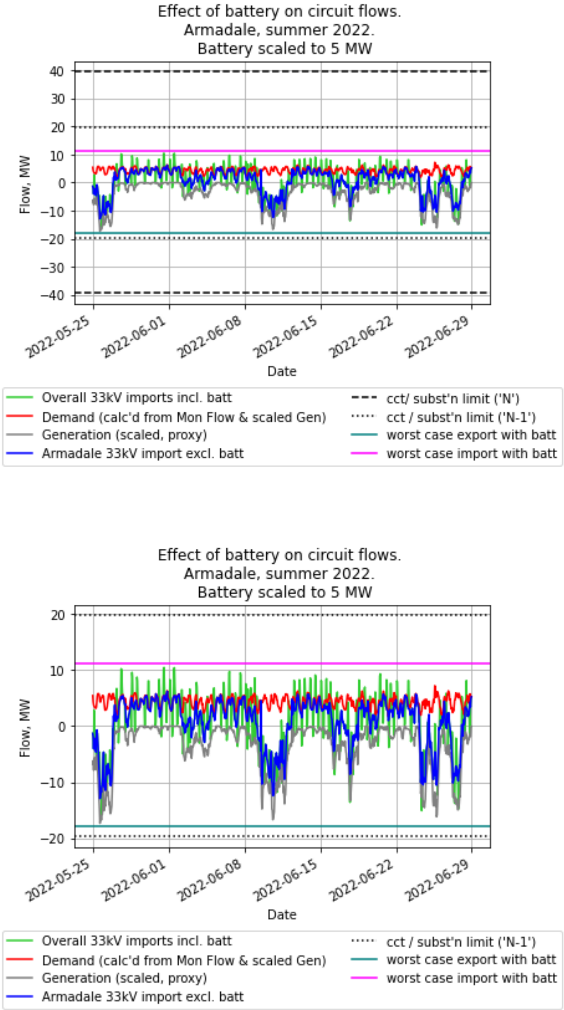


(e) Lochan Moor, Autumn

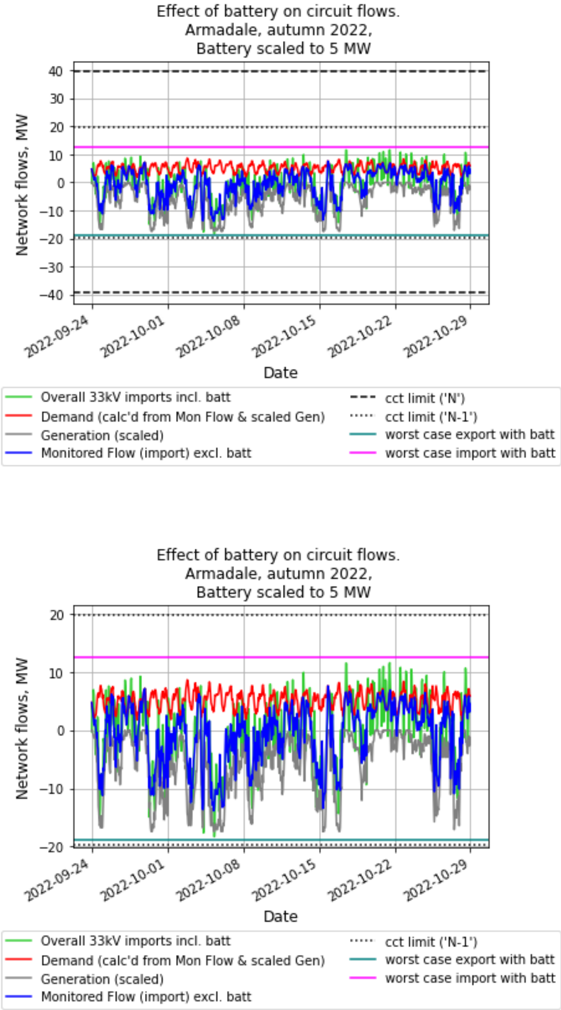


(f) Lochan Moor, Winter

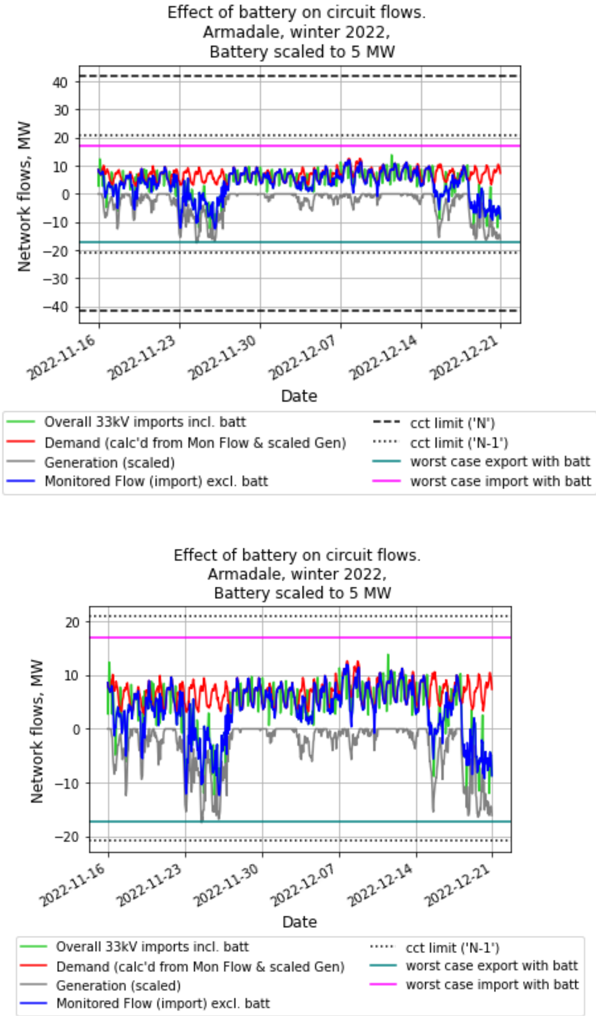
Annex 11B 3. Battery scaled to 5 MW. Armadale (Monitored Flows rescaled). Scaled showing "N" and "N-1"circuit capacities



(a) Armadale, Summer

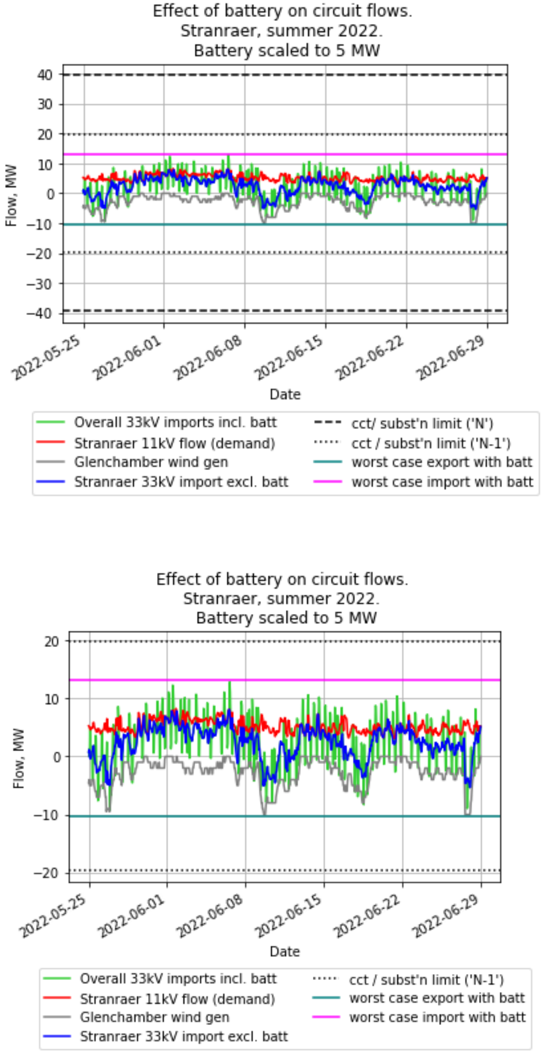


(b) Armadale, Autumn

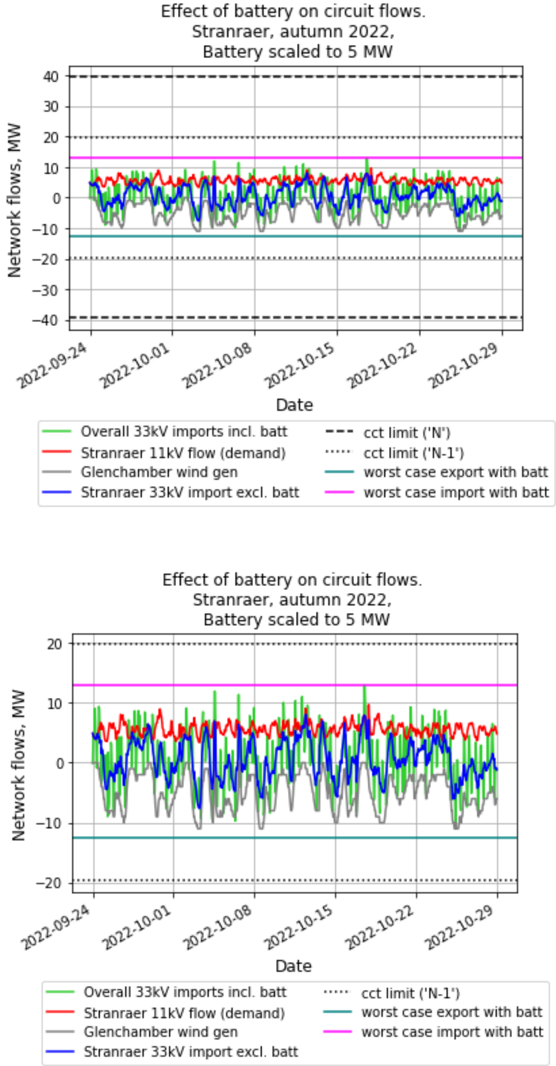


(c) Armadale, Winter

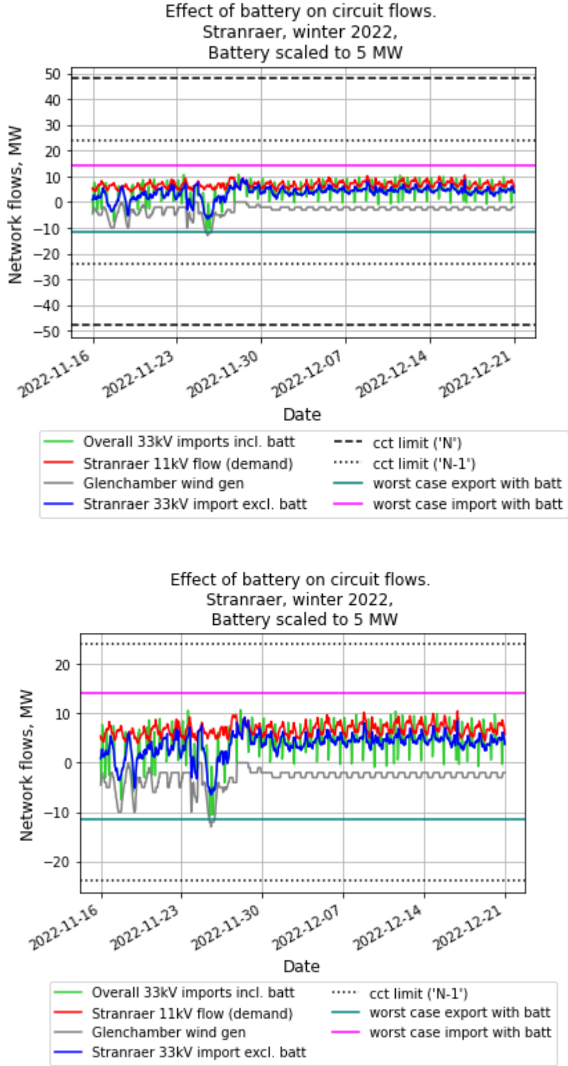
Annex 11B 4. Battery scaled to 5 MW. Stranraer. Scaled showing “N” and “N-1”circuit capacities



(a) Stranraer, Summer

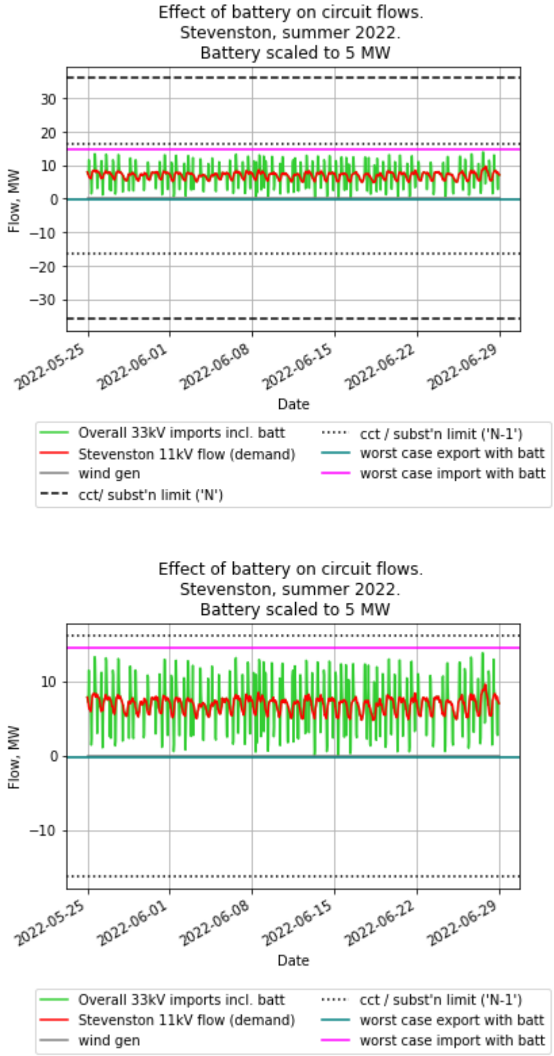


(b) Stranraer, Autumn

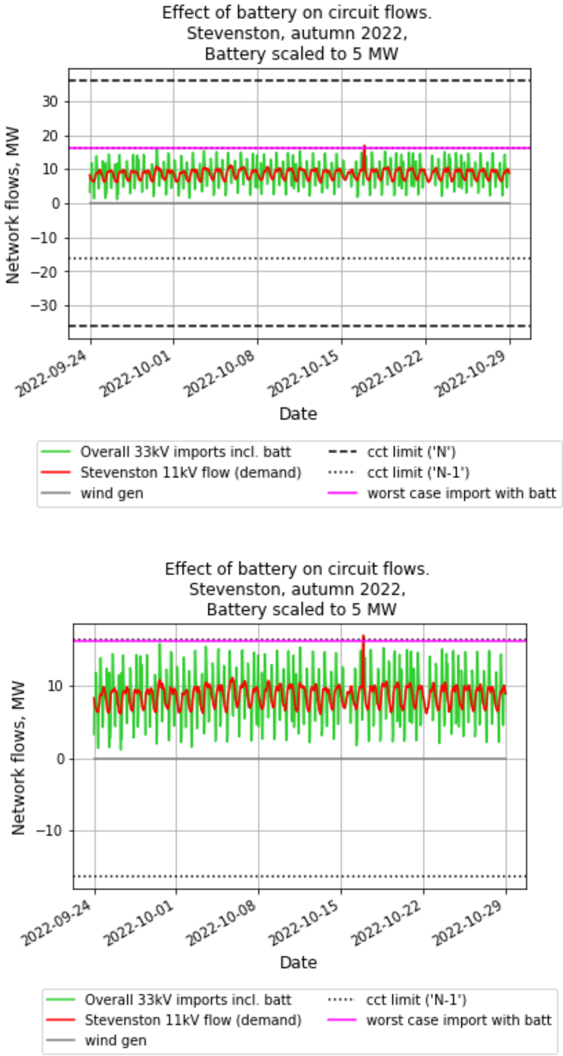


(c) Stranraer, Winter

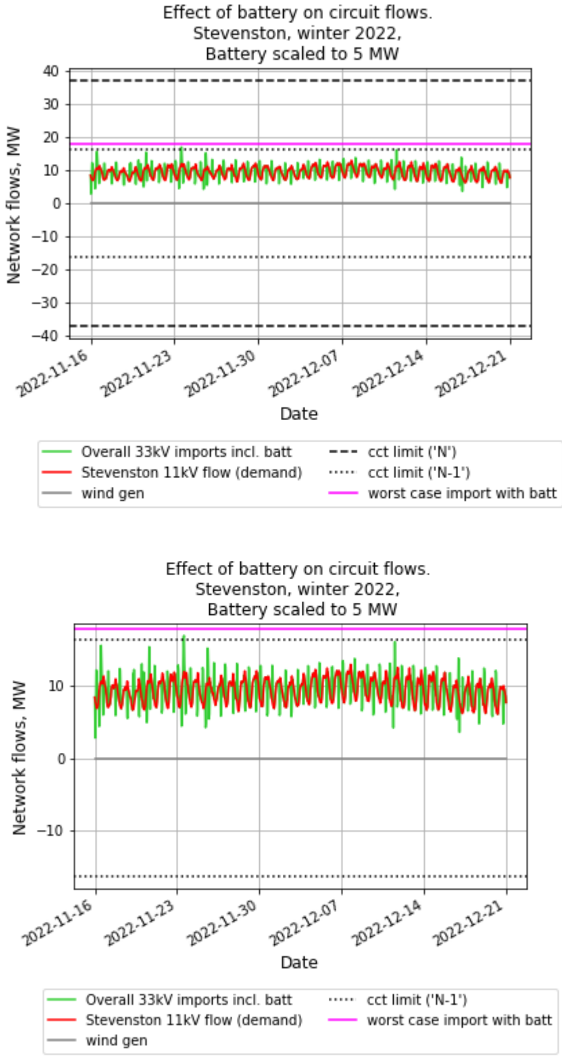
Annex 11B 5. Battery scaled to 5 MW. Stevenston. Scaled showing "N" and "N-1" circuit capacities



(a) Stevenston, Summer



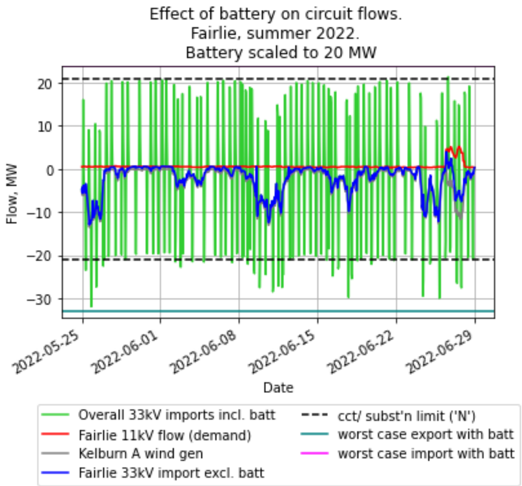
(b) Stevenston, Autumn



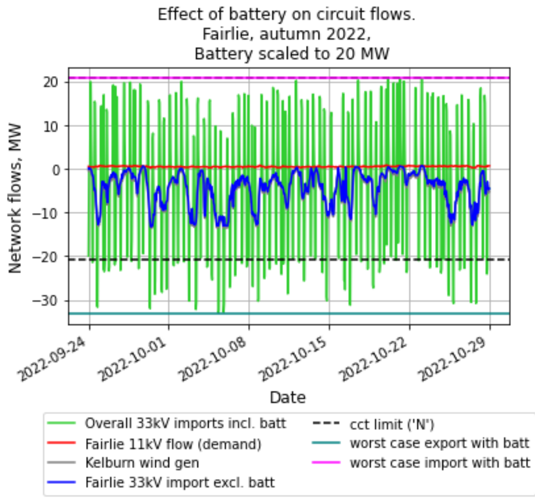
(c) Stevenston, Winter

Annex 11C Battery scaled to 20 MW

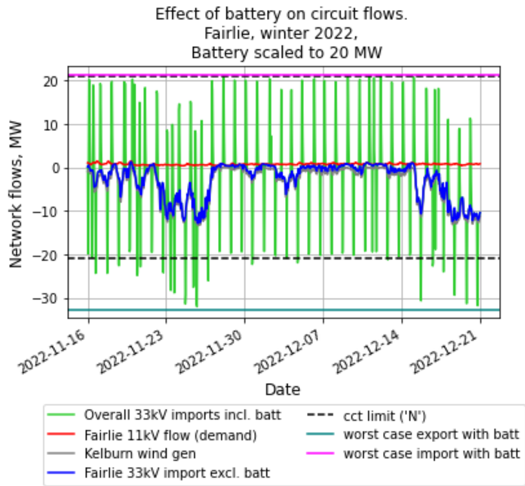
*Annex 11C 1. Battery scaled to 20 MW: **Fairlie & Largs***



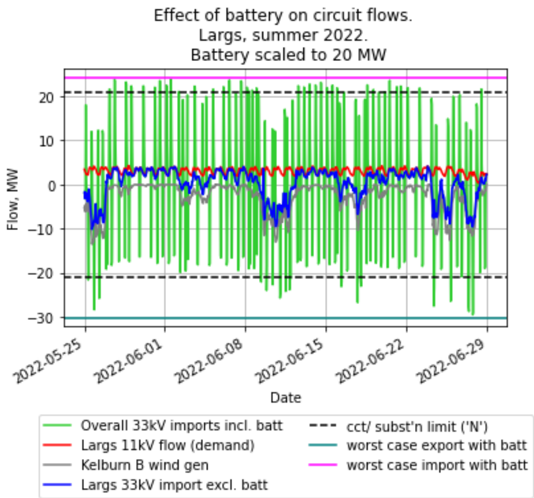
(a) Fairlie, Summer



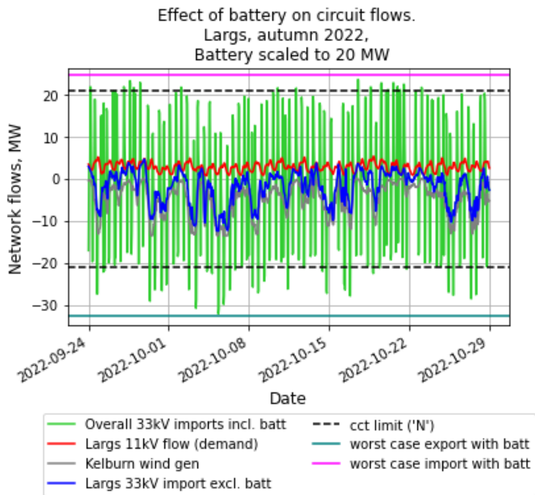
(b) Fairlie, Autumn



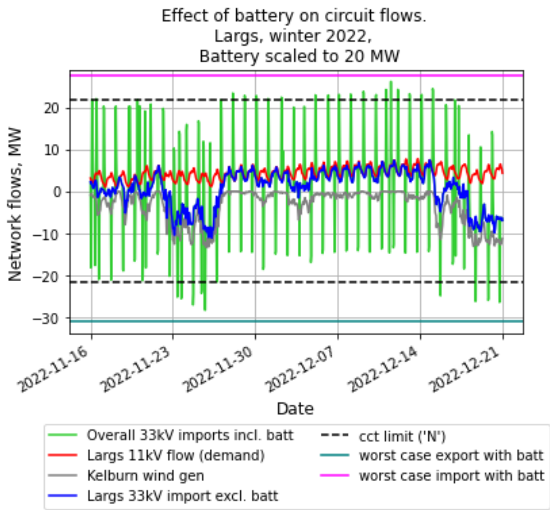
(c) Fairlie, Winter



(d) Largs, Summer

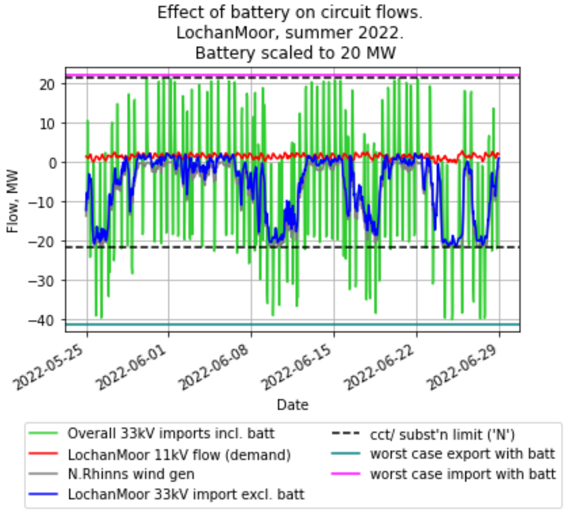


(e) Largs, Autumn

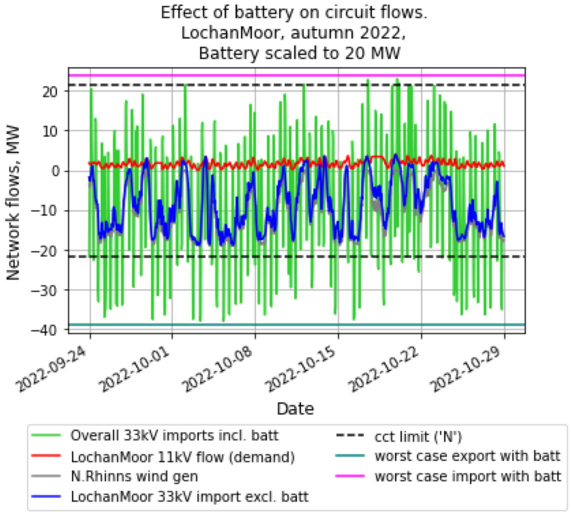


(f) Largs, Winter

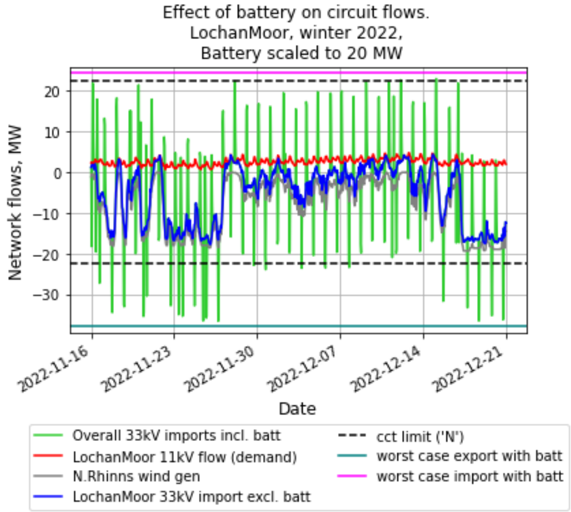
*Annex 11C 2. Battery scaled to 20 MW: **Lochan Moor***



(a) Lochan Moor, Summer

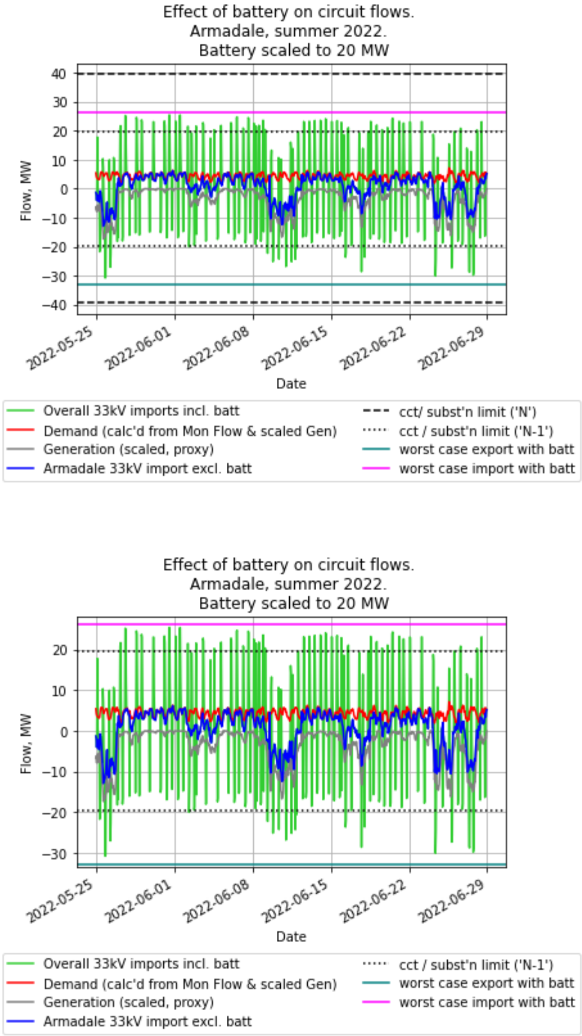


(b) Lochan Moor, Autumn

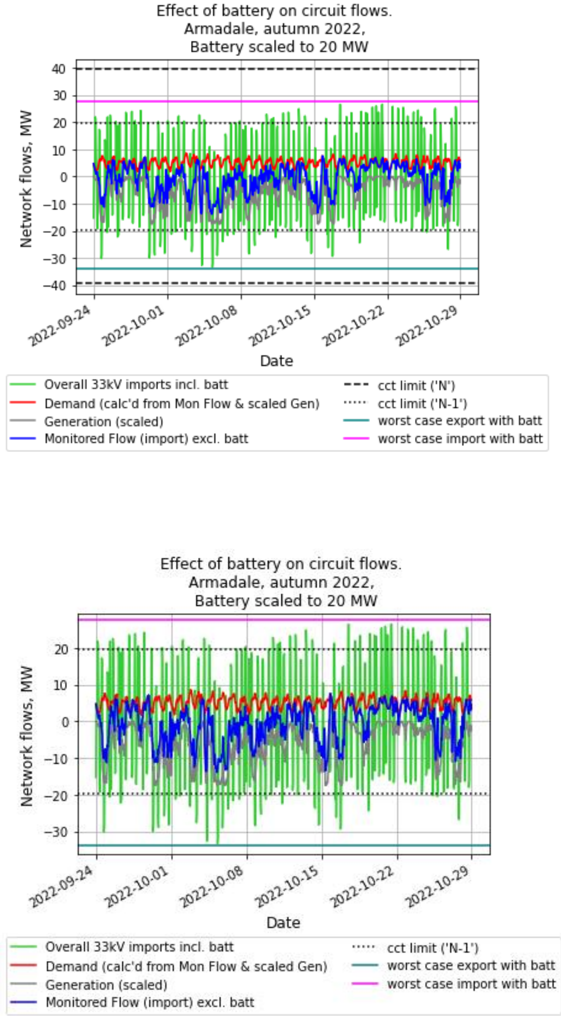


(c) Lochan Moor, Winter

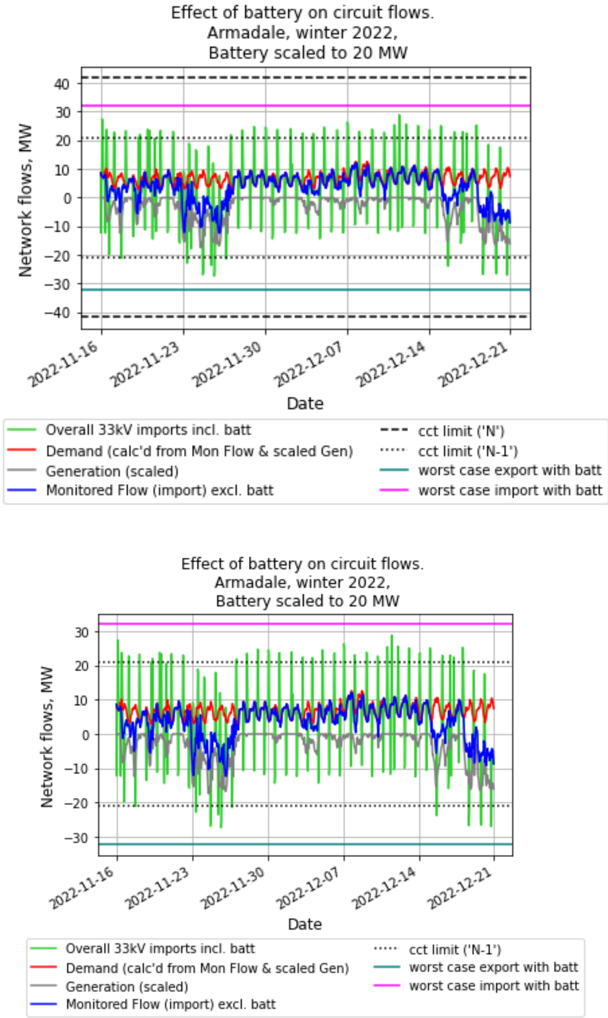
*Annex 11C 3. Battery scaled to 20 MW: **Armadale.** Scaled showing "N" and "N-1" circuit limits*



(a) Armadale, Summer

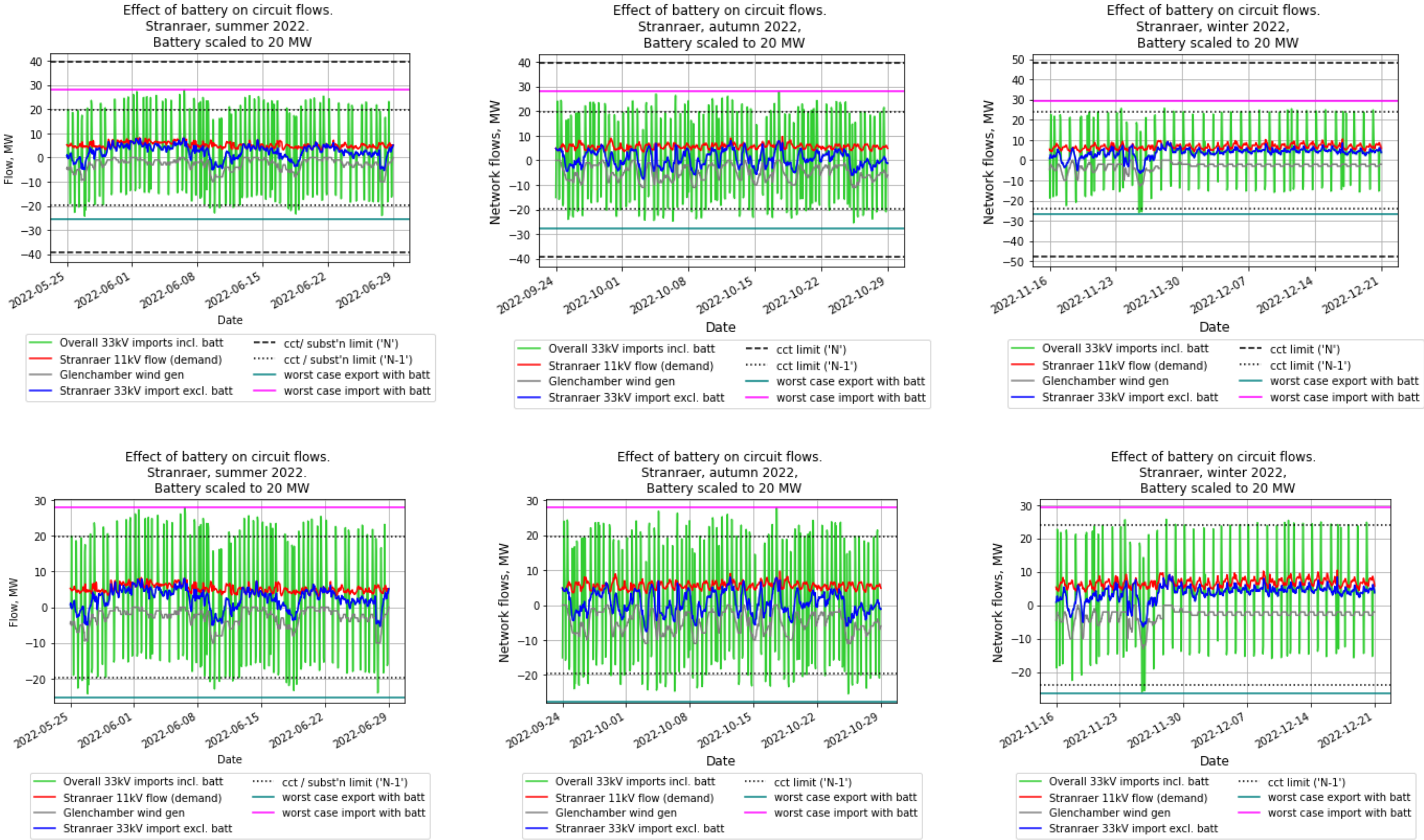


(b) Armadale, Autumn



(c) Armadale, Winter

*Annex 11C 4. Battery scaled to 20 MW: **Stranraer.** Scaled showing "N" and "N-1" circuit limits*

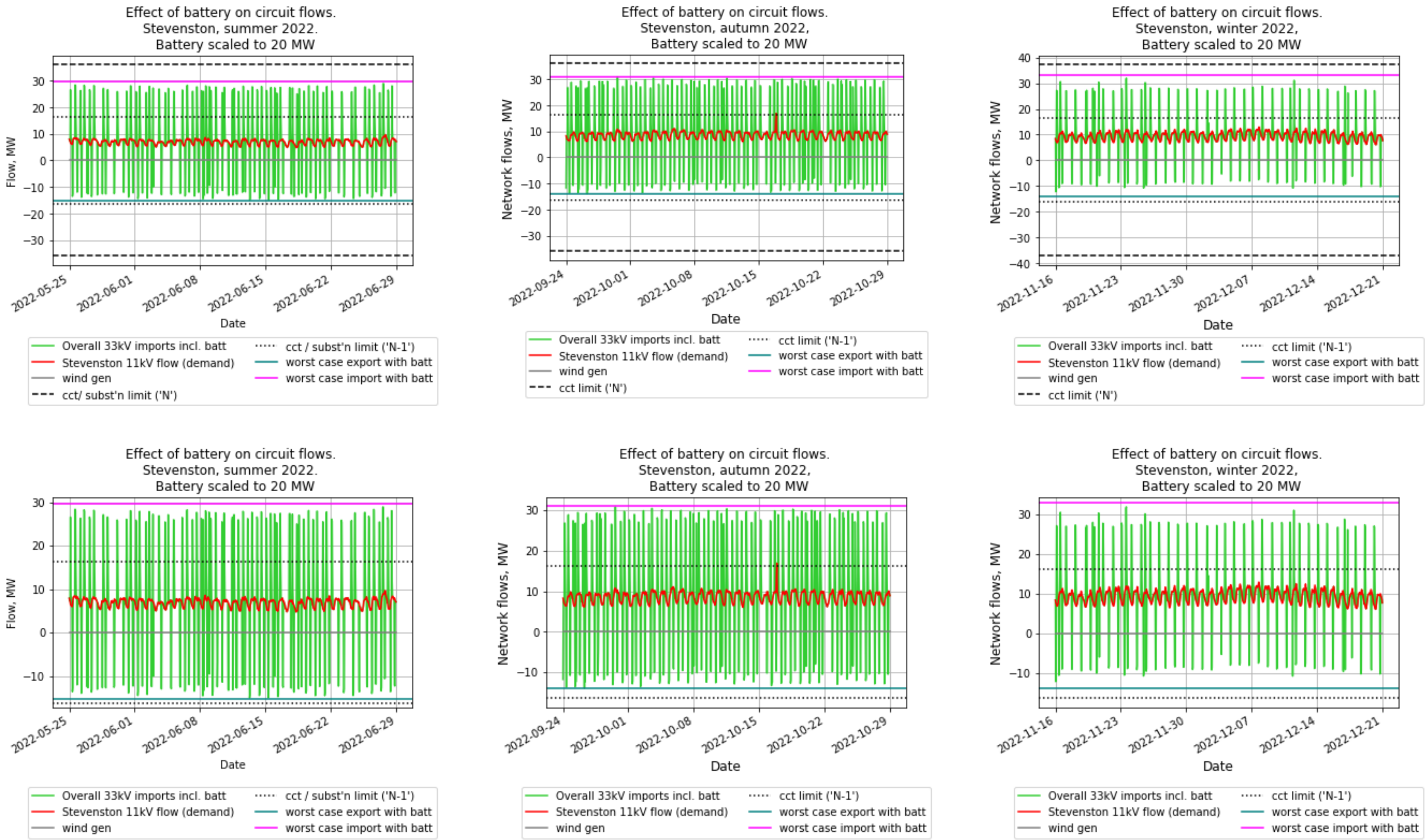


(a) Stranraer, Summer

(b) Stranraer, Autumn

(c) Stranraer, Winter

*Annex 11C 5. Battery scaled to 20 MW: **Stevenston.** Scaled showing "N" and "N-1" circuit limits*



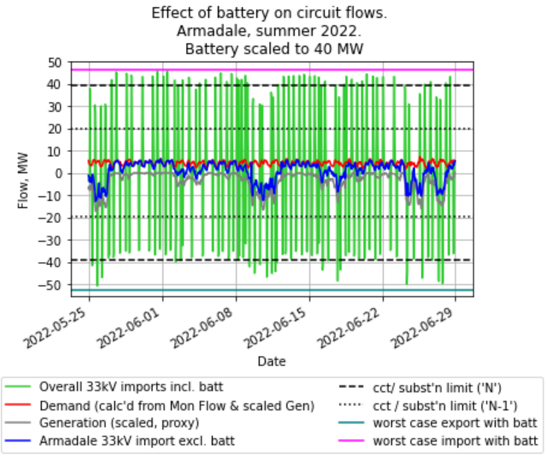
(a) Stevenston, Summer

(b) Stevenston, Autumn

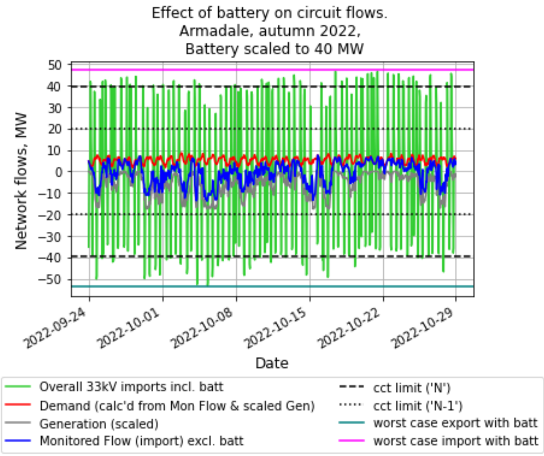
(c) Stevenston, Winter

Annex 11D Battery scaled to 40 MW

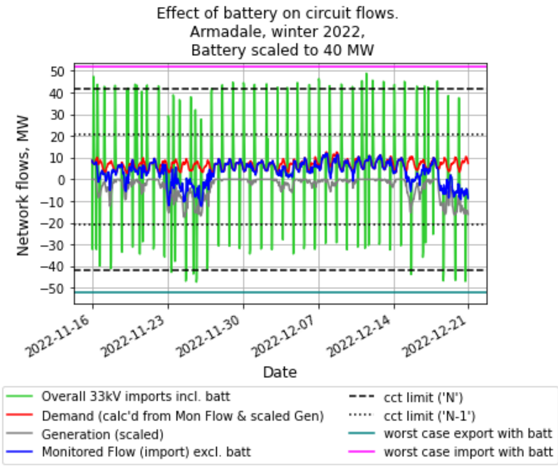
*Annex 11D 1. Battery scaled to 40 MW: **Armadale and Stranraer***



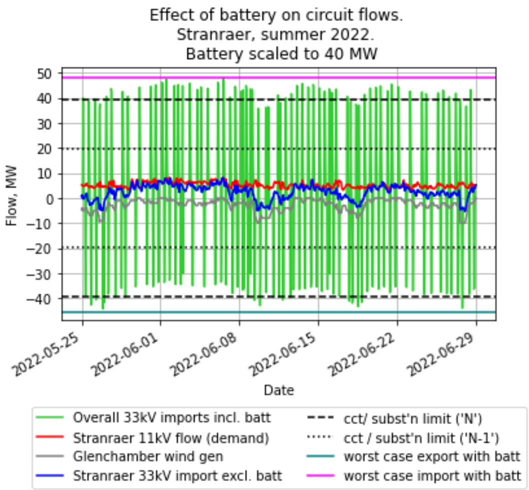
(a) Armadale, Summer



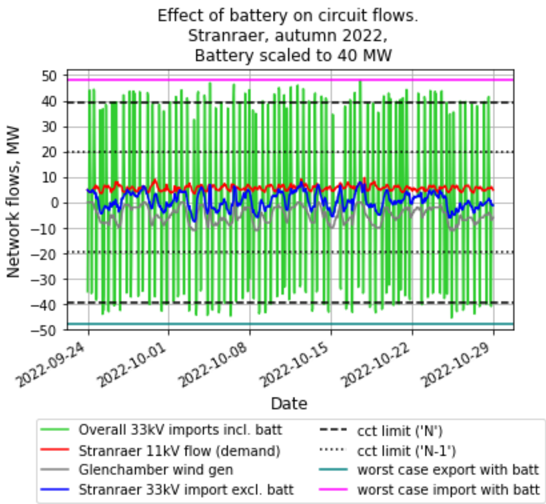
(b) Armadale, Autumn



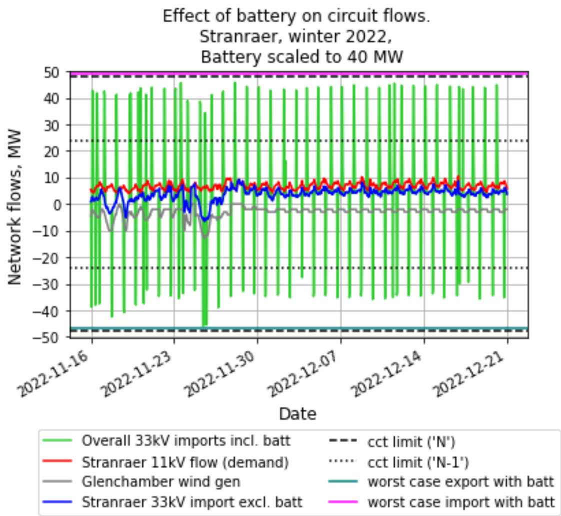
(c) Armadale, Winter



(d) Stranraer, Summer

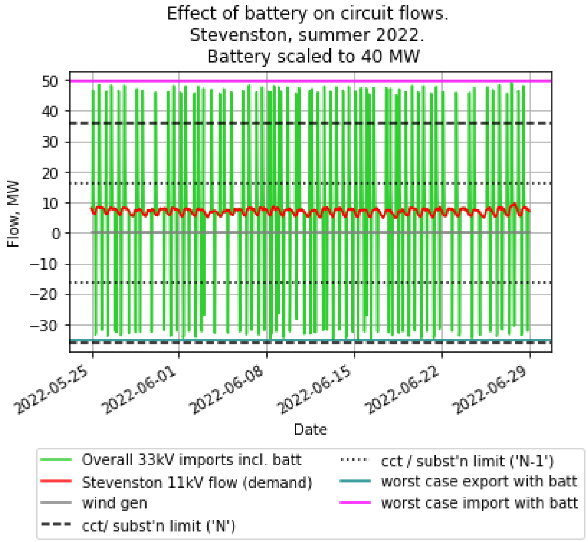


(e) Stranraer, Autumn

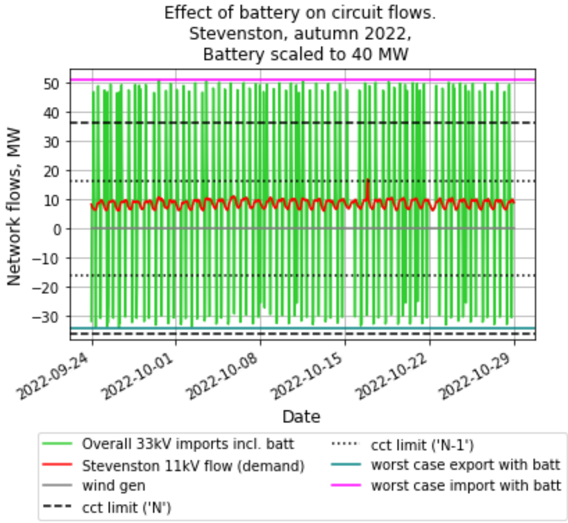


(f) Stranraer, Winter

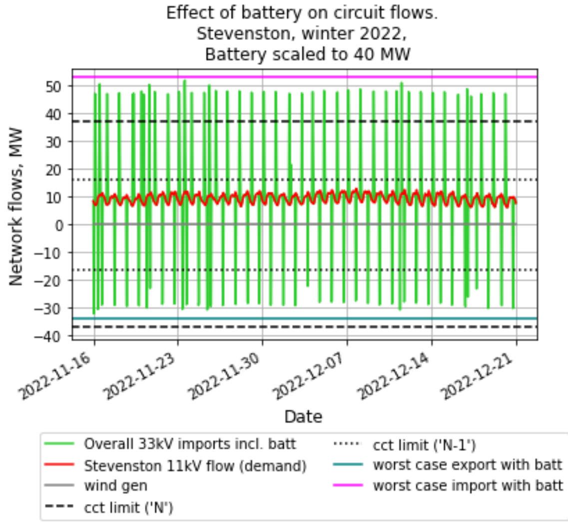
*Annex 11D 2. Battery scaled to 40 MW: **Stevenston***



(a)Stevenston, Summer



(b) Stevenston, Autumn



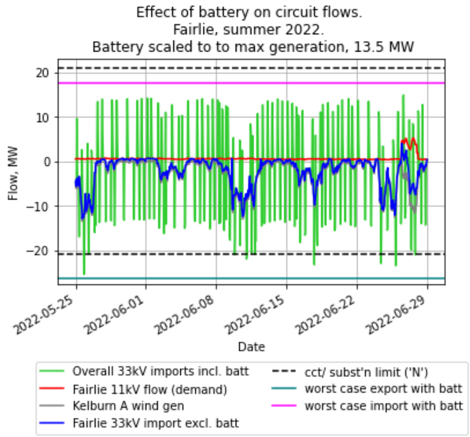
(c) Stevenston, Winter

Chapter 6 Annex 12

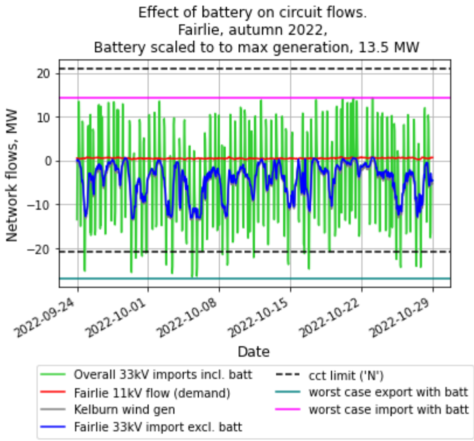
Circuit flows with additional battery: scaled to generation, demand and demand variation.

Annex 12A Battery scaled to maximum generation

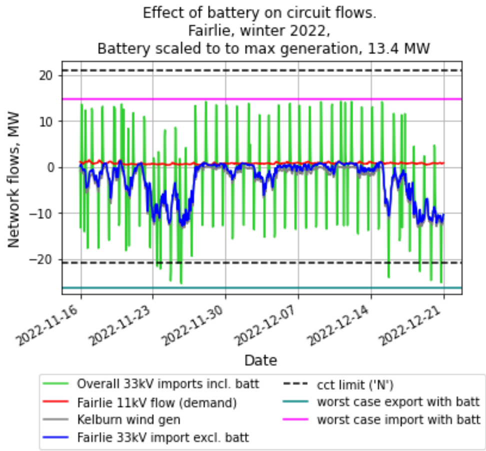
*Annex 12A 1. Battery scaled to maximum generation: **Fairlie and Largs***



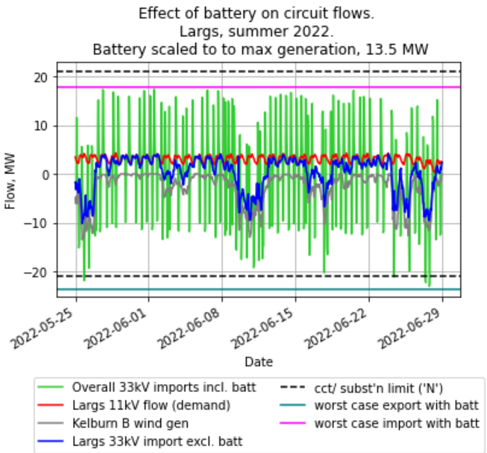
(a) Fairlie, Summer



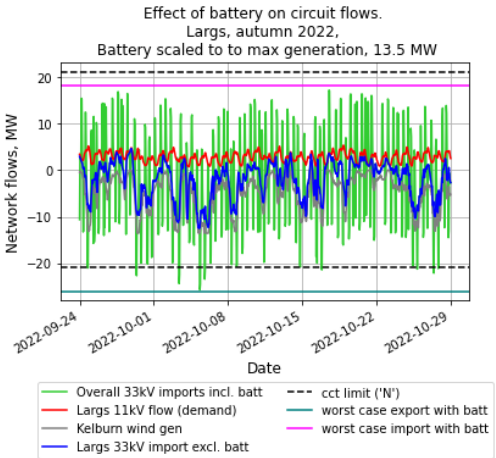
(b)Fairlie, Autumn



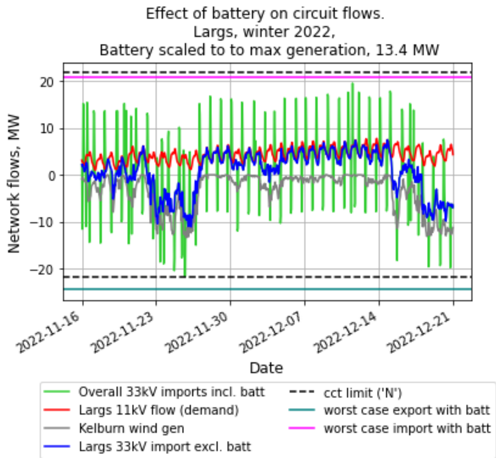
(c) Fairlie, Winter



(d) Largs, Summer

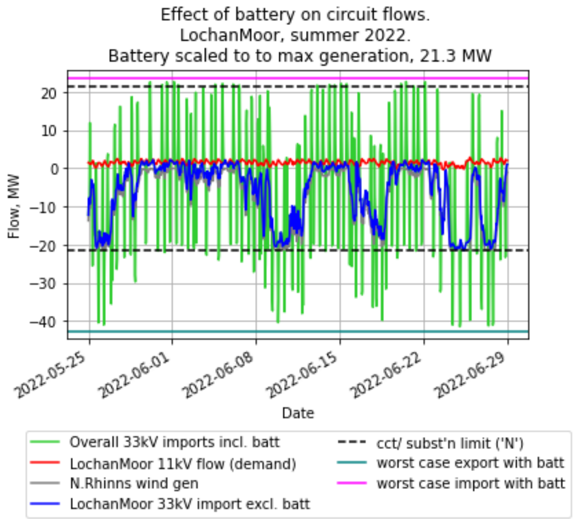


(e) Largs, Autumn

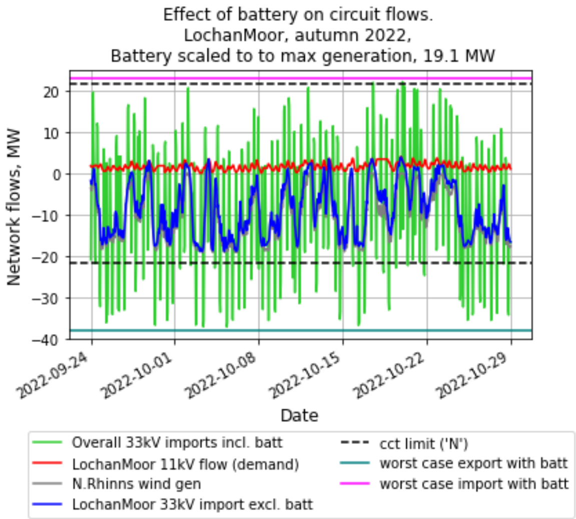


(f) Largs, Winter

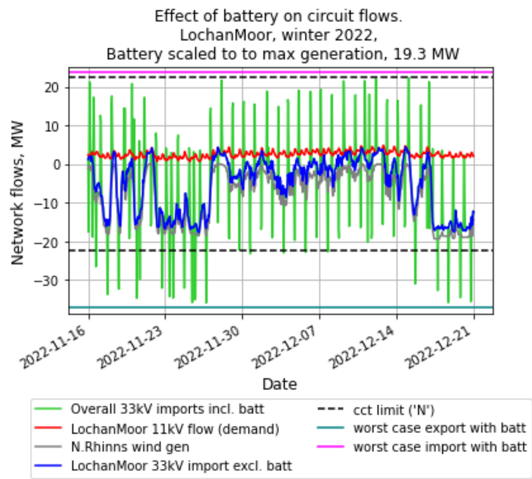
*Annex 12A 2. Battery scaled to maximum generation: **Lochan Moor***



(a) Lochan Moor, Summer

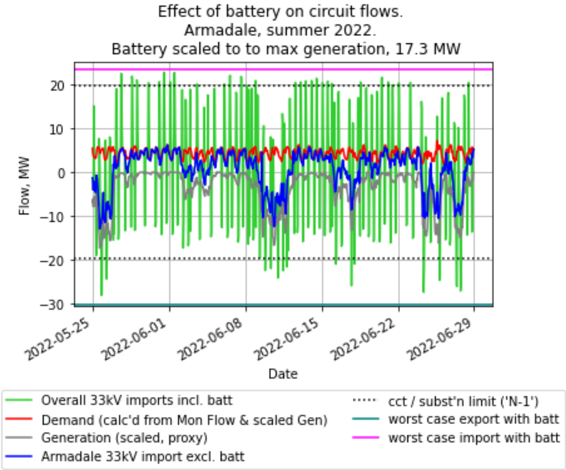


(b)Lochan Moor, Autumn

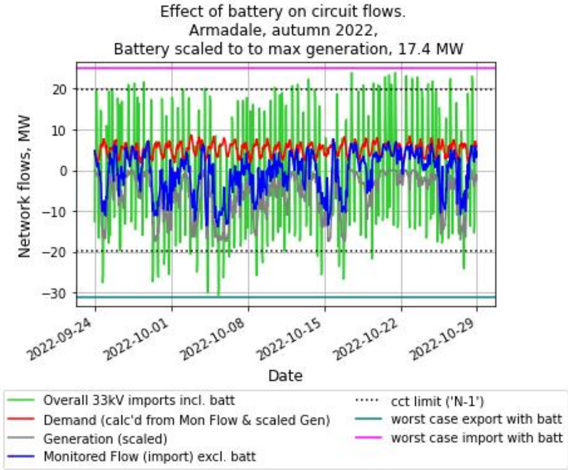


(c) Lochan Moor, Winter

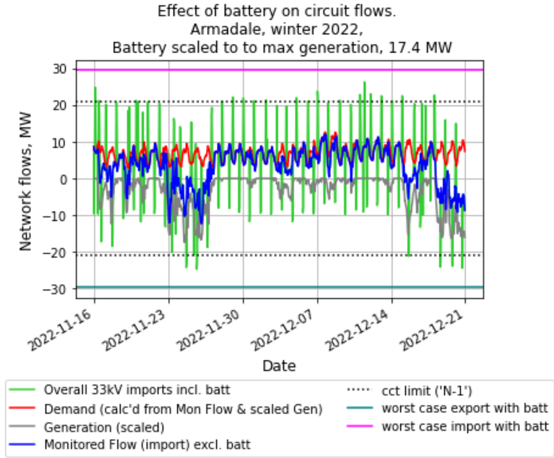
*Annex 12A 3. Battery scaled to maximum generation: **Armadale and Stranraer***



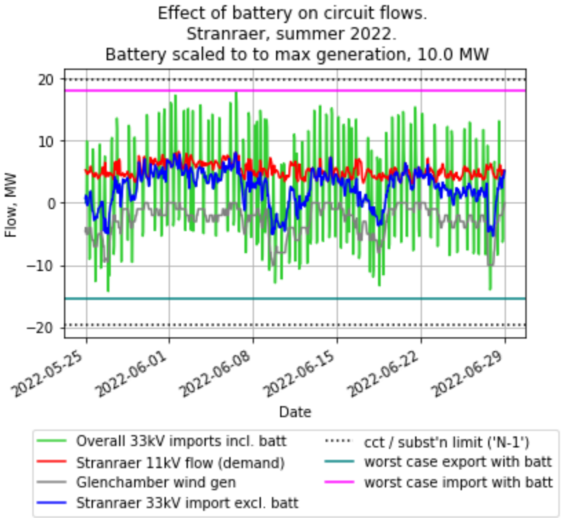
(a) Armadale, Summer



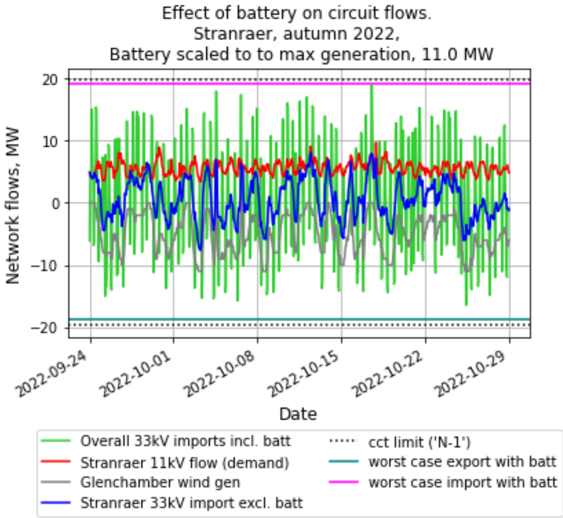
(b)Armadale, Autumn



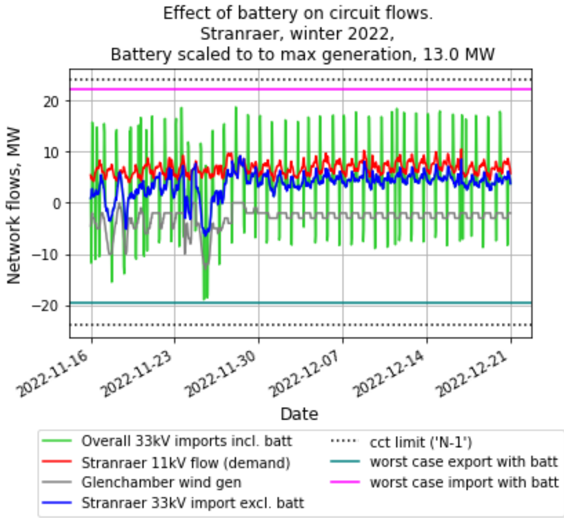
(c) Armadale, Winter



(d) Stranraer, Summer



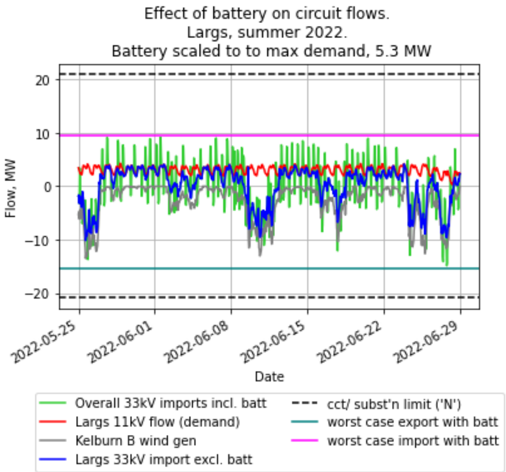
(e)Stranraer, Autumn



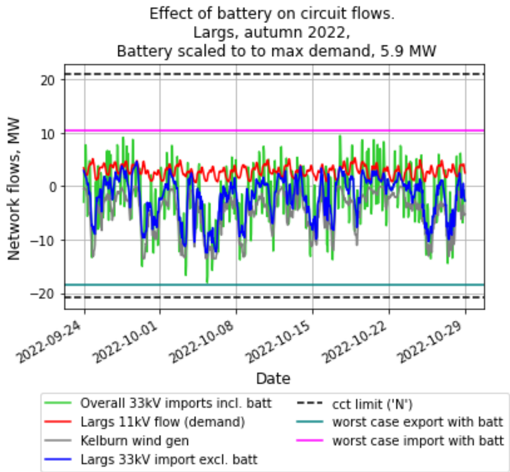
(f) Stranraer, Winter

Annex 12B Battery scaled to maximum demand

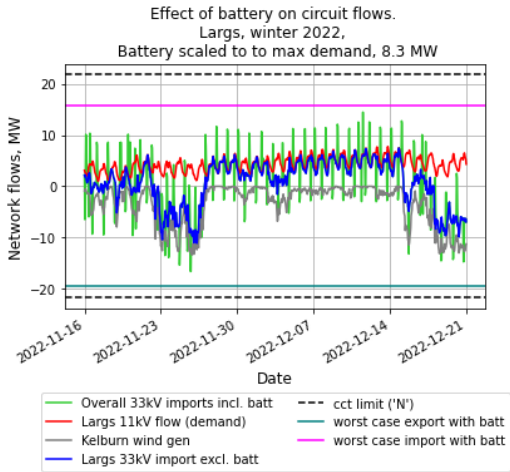
*Annex 12B 1. Battery scaled to maximum demand: **Largs and Lochan Moor***



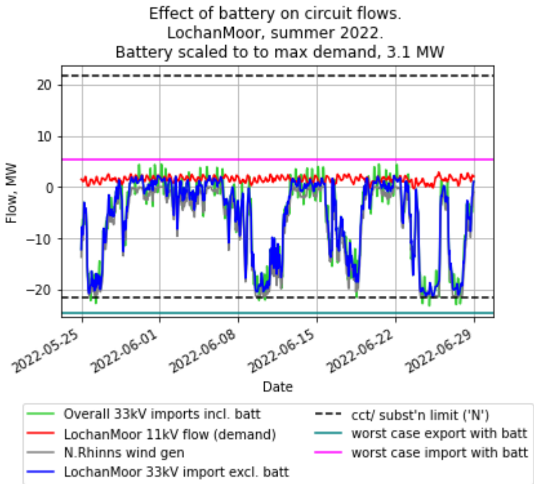
(a) Largs, Summer



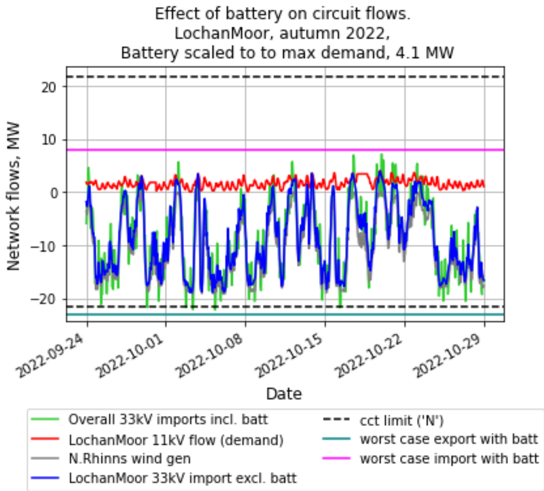
(b)Largs, Autumn



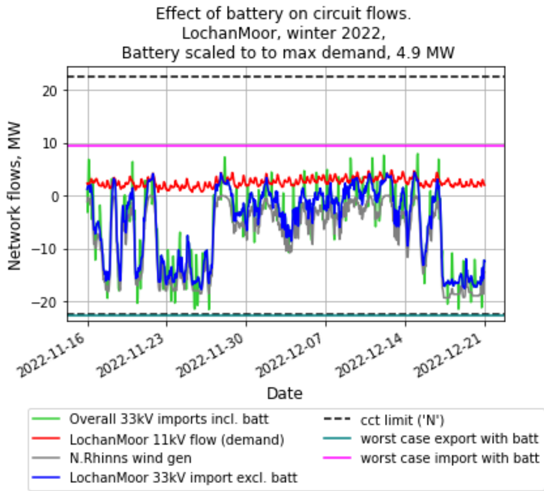
(c)Largs, Winter



(a) Lochan Moor, Summer

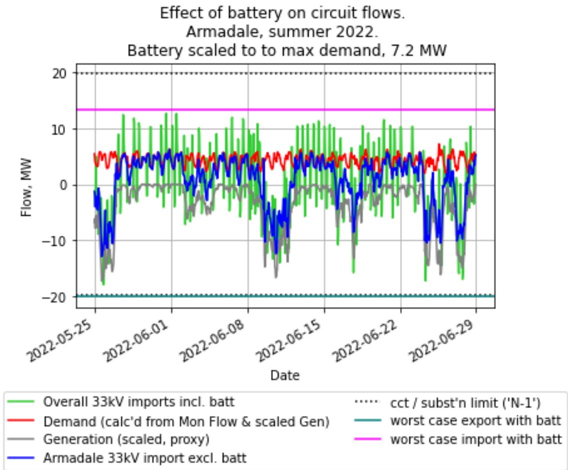


(e) Lochan Moor, Autumn

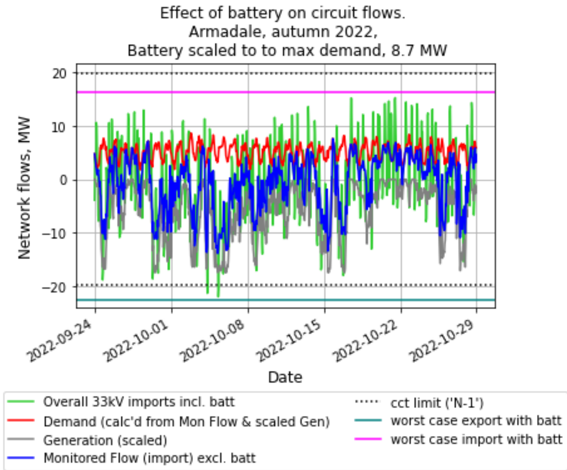


(f) Lochan Moor, Winter

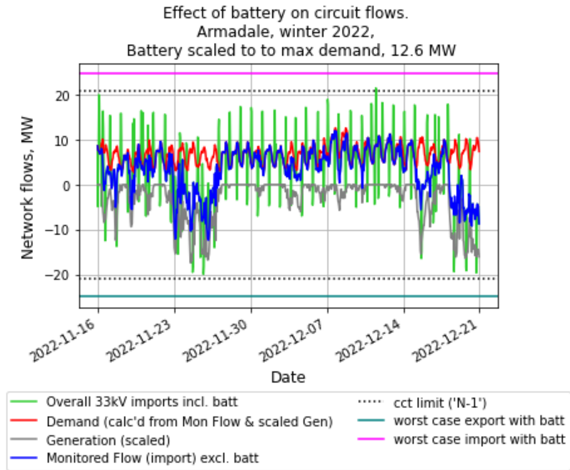
Annex 12B 2. Battery scaled to maximum demand: ***Armadale and Stranraer***



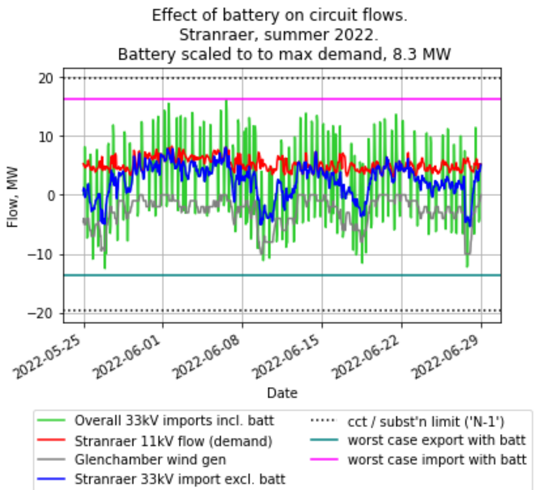
(a) Armadale, Summer



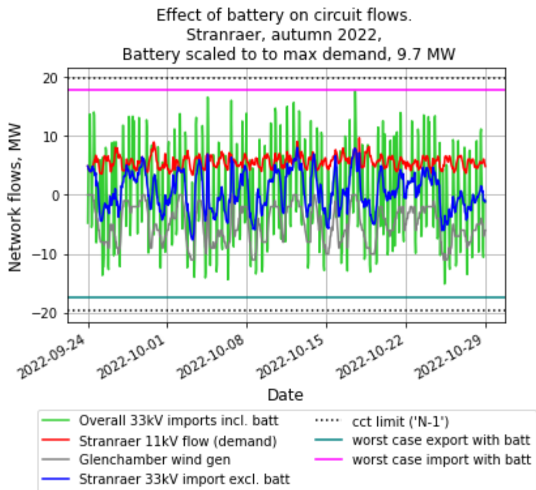
(b) Armadale , Autumn



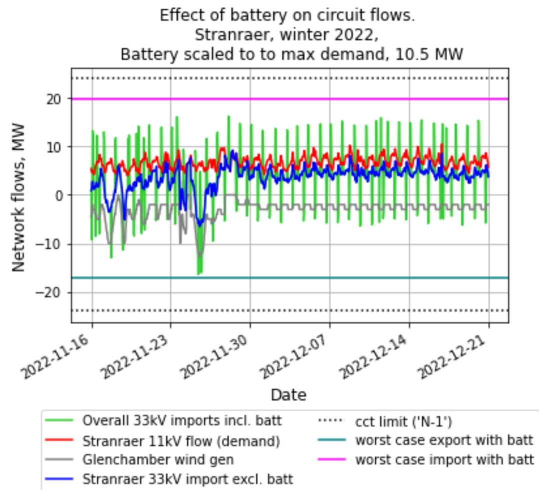
(c) Armadale, Winter



(d) Stranraer, Summer



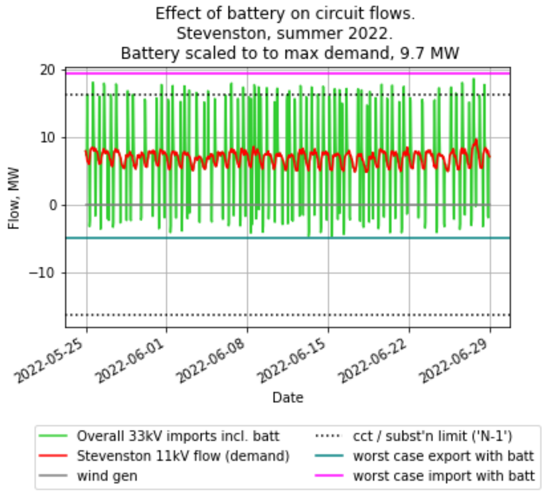
(e) Stranraer, Autumn



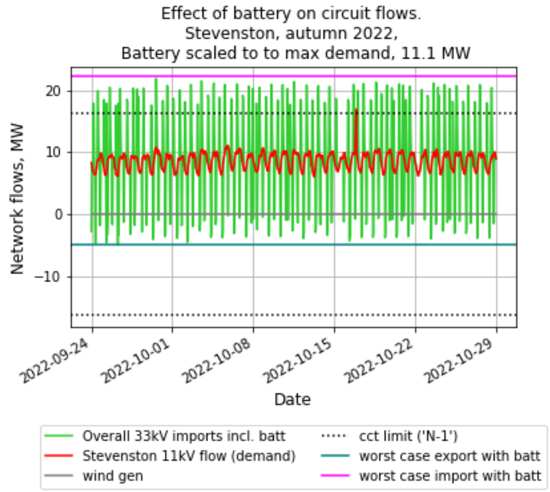
(f) Stranraer, Winter

*Annex 12B 3. Battery scaled to maximum demand: **Stevenston***

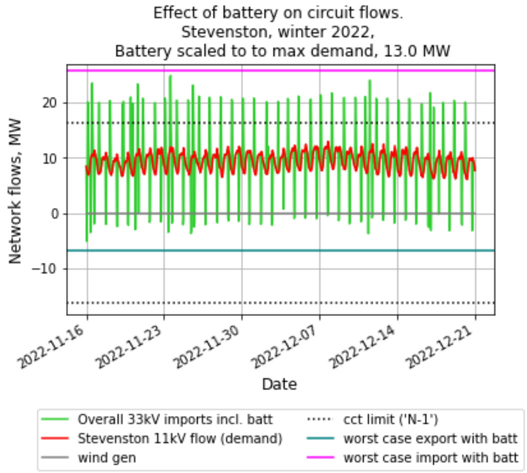
(Maximum demand value omits the abnormal demand spike on 19 October)



(a) Stevenston, Summer



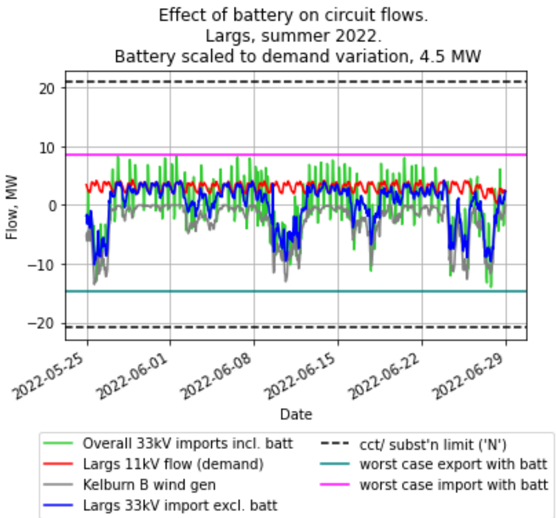
(b) Stevenston, Autumn



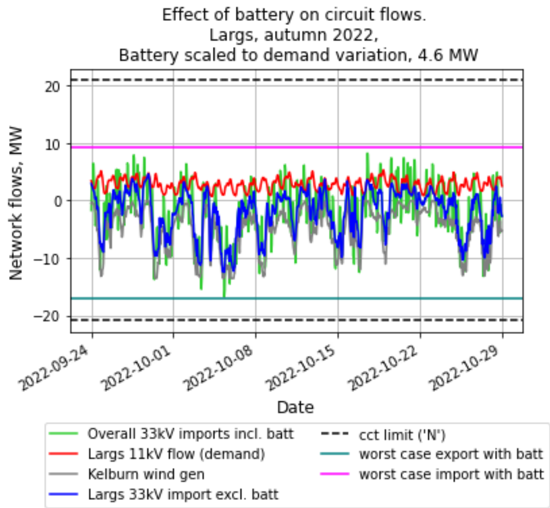
(c) Stevenston, Winter

Annex 12C Battery scaled to demand *variation*

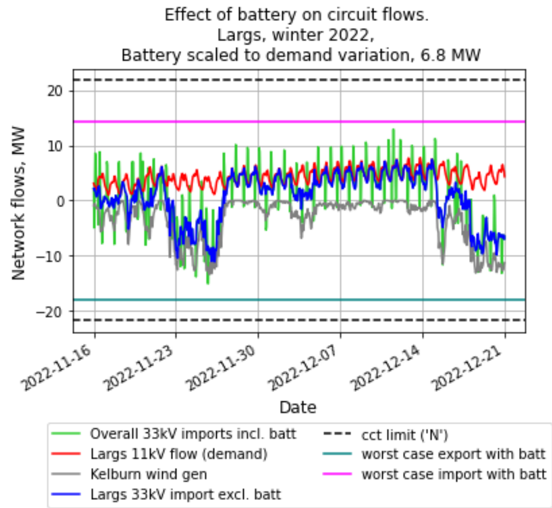
*Annex 12C 1. Battery scaled to demand variation: **Largs and Lochan Moor***



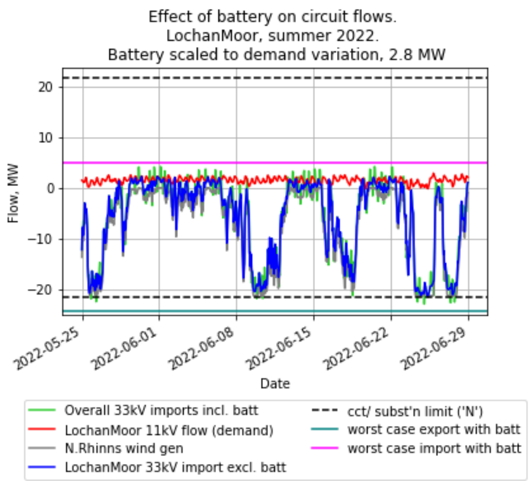
(a) Largs, Summer



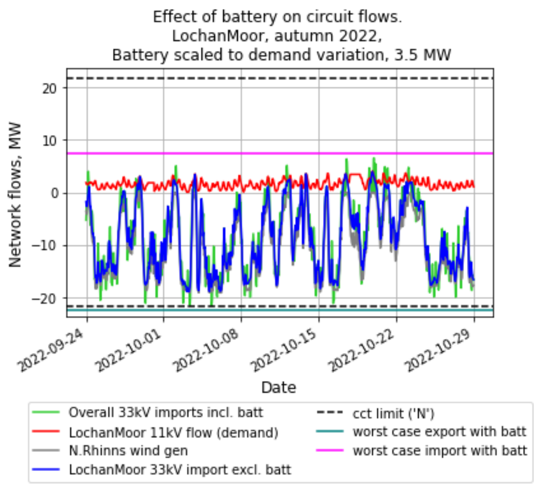
(b) Largs, Autumn



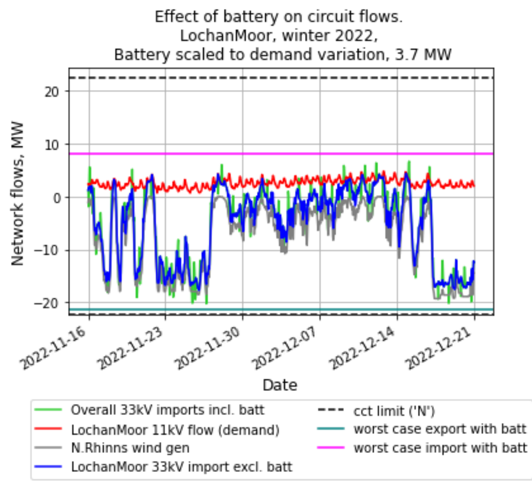
(c) Largs, Winter



(d) Lochan Moor, Summer

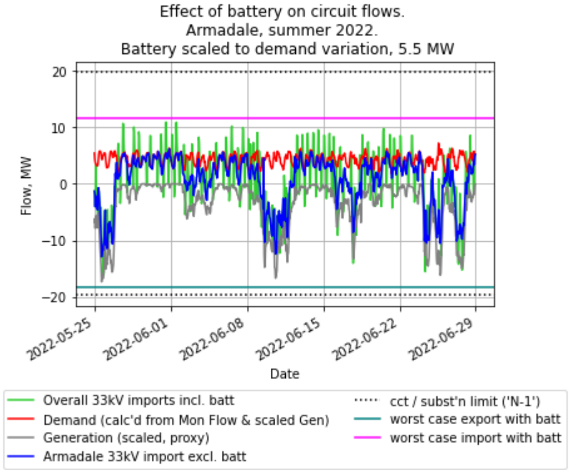


(e) Lochan Moor, Autumn

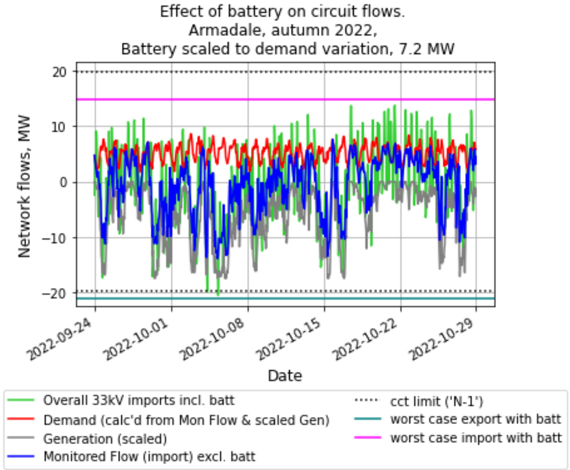


(f) Lochan Moor, Winter

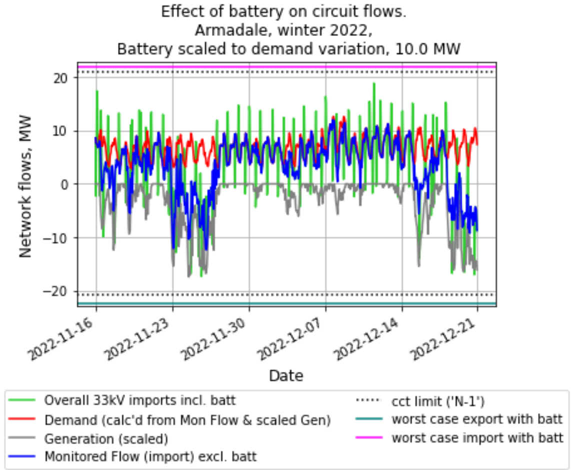
*Annex 12C 2. Battery scaled to demand variation: **Armadale and Stranraer***



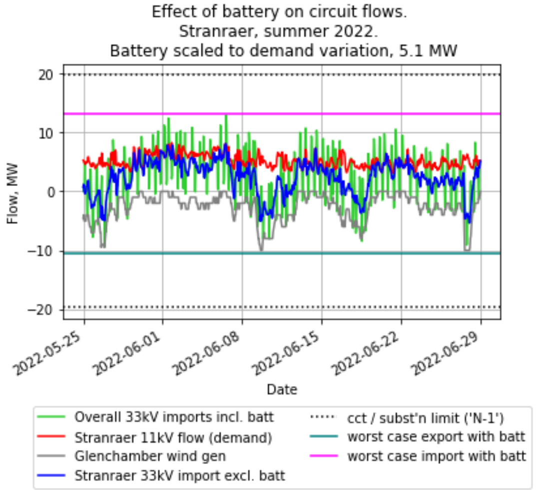
(a) Armadale, Summer



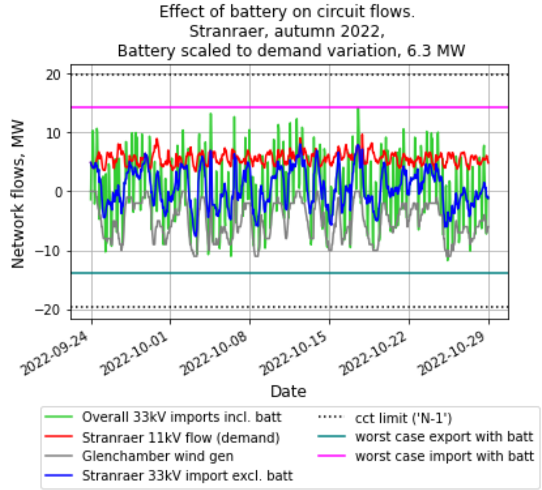
(b)Armadale , Autumn



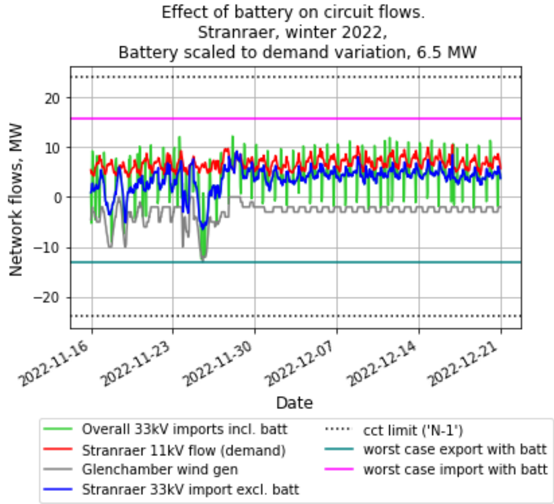
(c) Armadale, Winter



(d) Stranraer, Summer



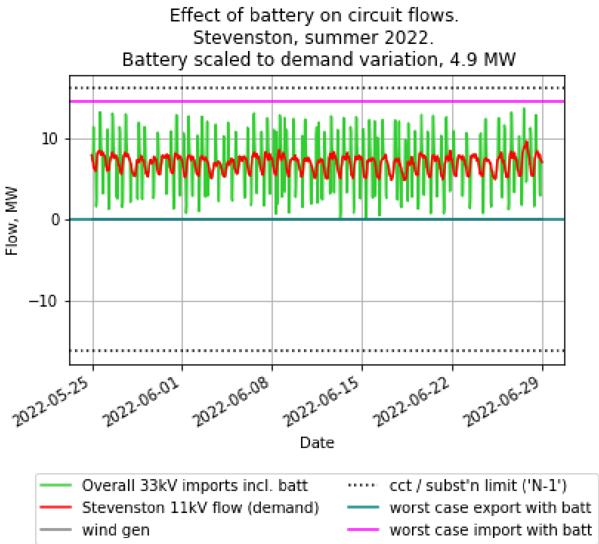
(e) Stranraer, Autumn



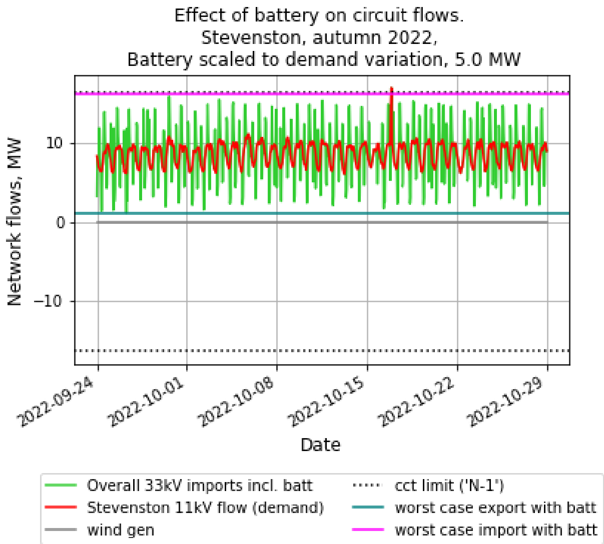
(f) Stranraer, Winter

*Annex 12C 3. Battery scaled to maximum demand variation: **Stevenston***

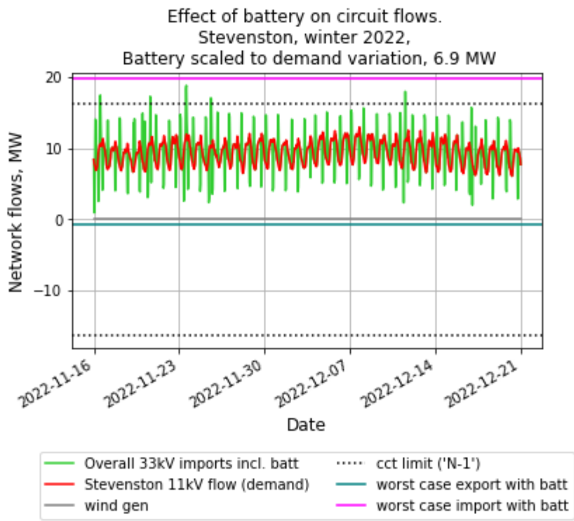
(Maximum demand variation value omits the abnormal demand spike on 19 October)



(a) Stevenston, Summer



(b) Stevenston, Autumn



(c) Stevenston, Winter

Chapter 6 Annex 13

Effect of battery duration and round-trip efficiency on circuit flows

This annex displays network flows with an additional battery, for 3 different battery durations (2-hr, 4-hr and 12-hr), all at 85% round-trip efficiency. For the 2-hr and 12-hr batteries, results are also displayed for batteries of 70% round-trip efficiency.

Trading parameters are as shown in Table 120.

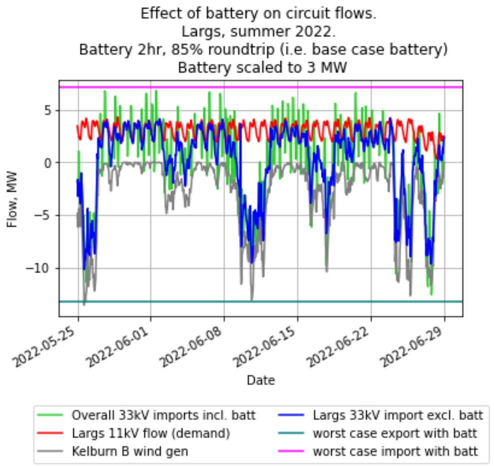
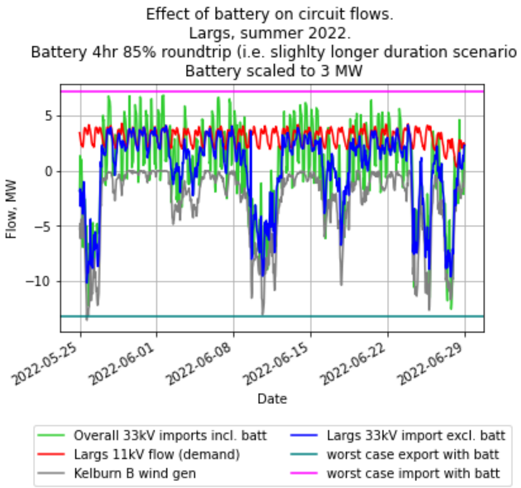
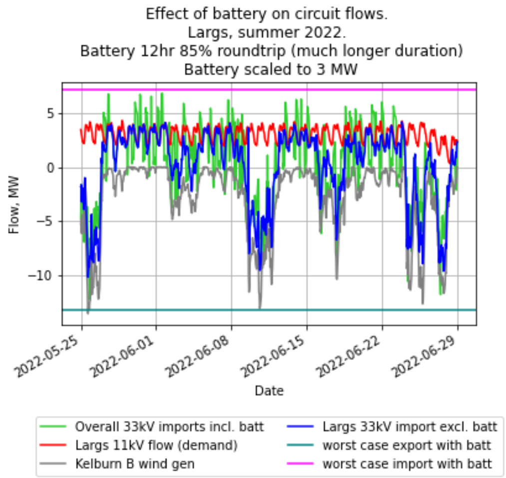
Batteries are sized at 3 MW, 5 MW and 20 MW.

Results are displayed for batteries located at

- Largs (moderately generation-dominated network flows) – 3MW, 5MW, 20 MW batteries
- Lochan Moor (strongly wind-dominated network flows) – 20 MW batteries
- and at Stevenston (demand-only network flows) – 3 MW batteries.

Annex 13A Summer

*Annex 13A 1. Summer - 3 MW battery, **Largs***

<table>
<tr><th>η</th><th>2 hour battery</th><th>4 hour battery</th><th>12 hour battery</th></tr>
<tr><td>85%</td><td>
</td><td>
</td><td>
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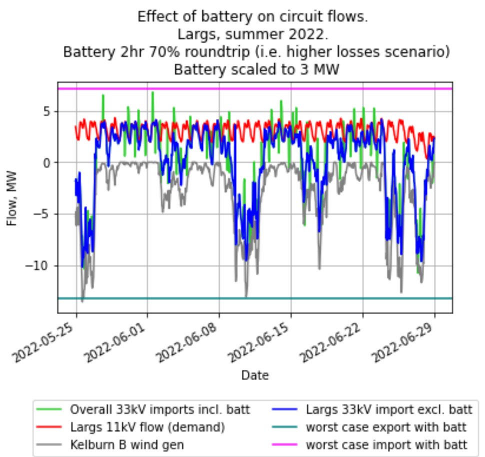
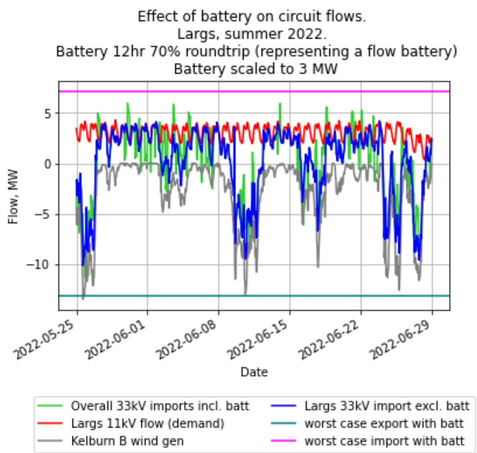
<tr><td>70%</td><td>
</td><td>Not modelled</td><td>
</td></tr>
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*Annex 13A 2. Summer - 5 MW battery, **Largs***

<table>
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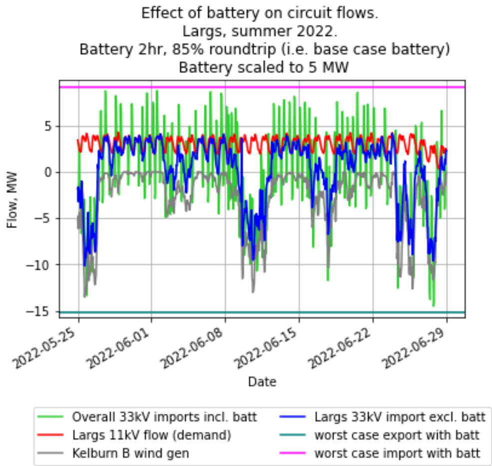
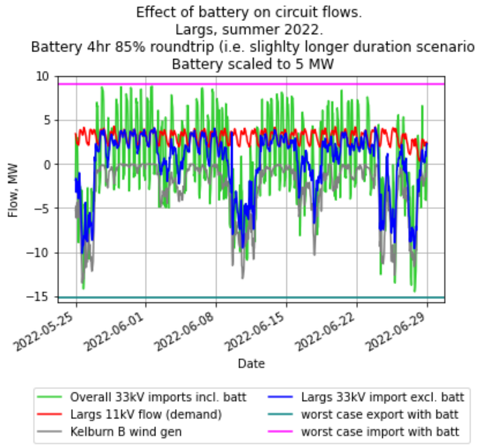
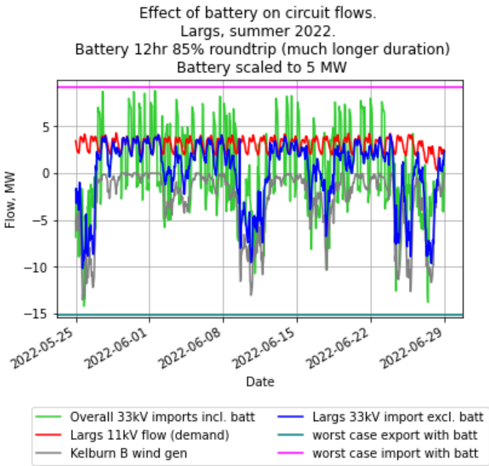
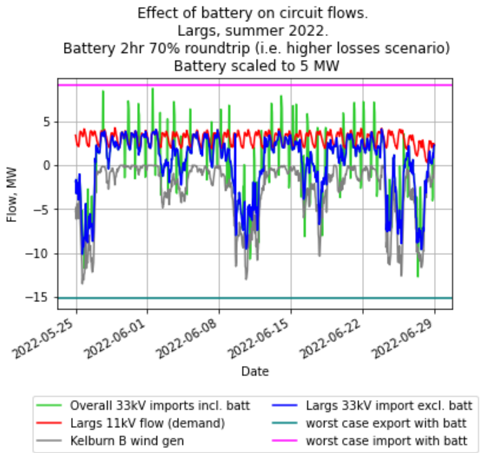
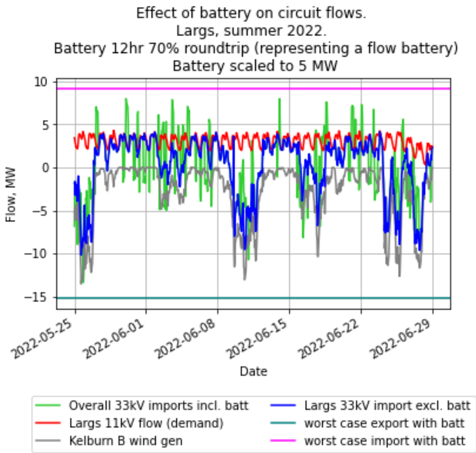
<tr><td>85%</td><td></td><td></td><td></td></tr>
<tr><td>70%</td><td></td><td>Not modelled</td><td></td></tr>
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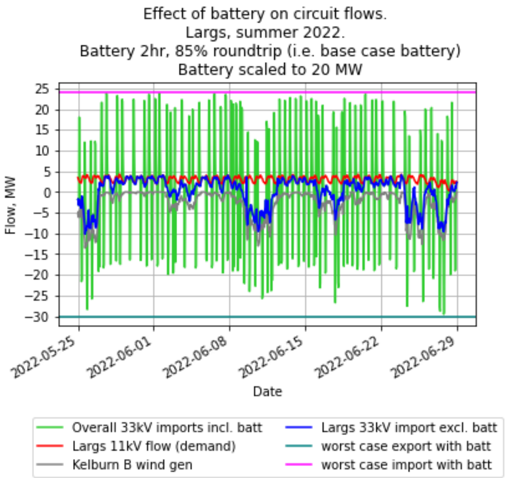
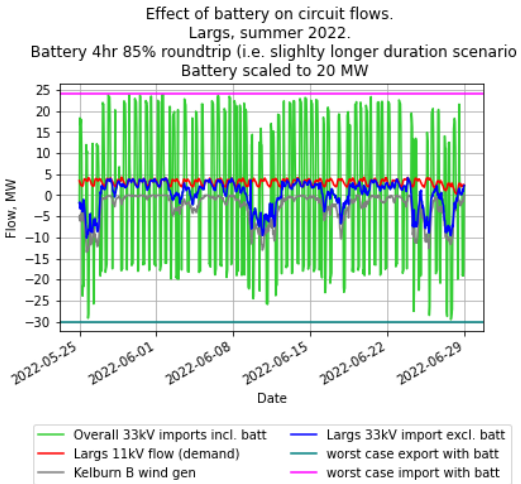
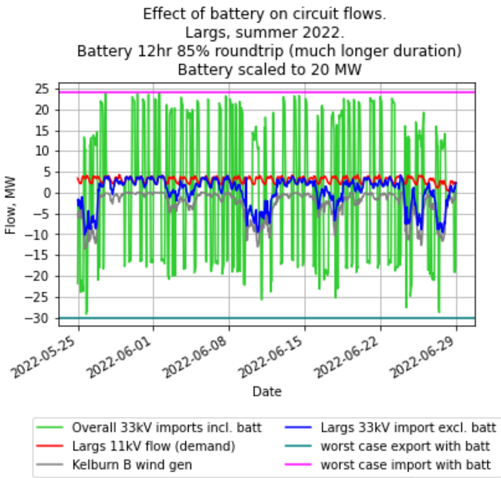
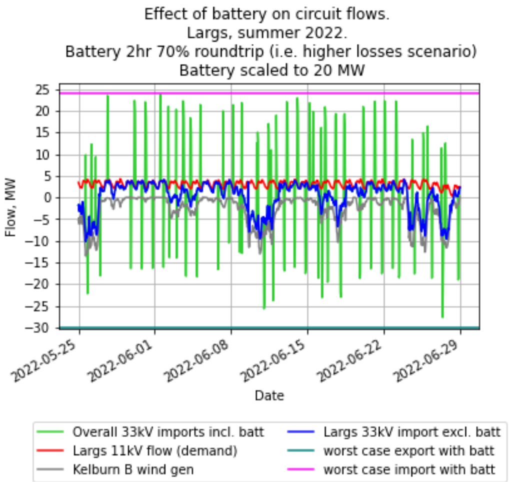
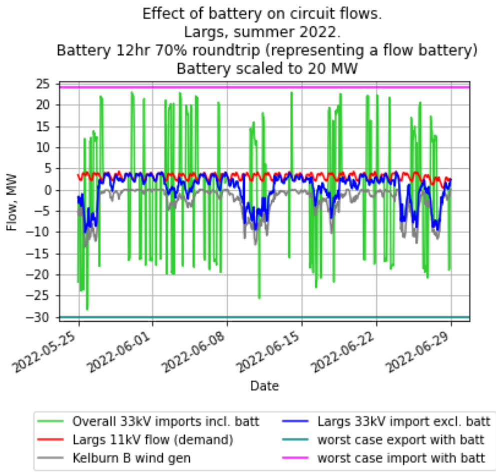
*Annex 13A 3. Summer - 20 MW battery, **Largs***

η	2 hour battery	4 hour battery	12 hour battery
85%			
70%		**Not modelled**	

*Annex 13A 4. Summer - 20 MW battery, **Lochan Moor***

<table>
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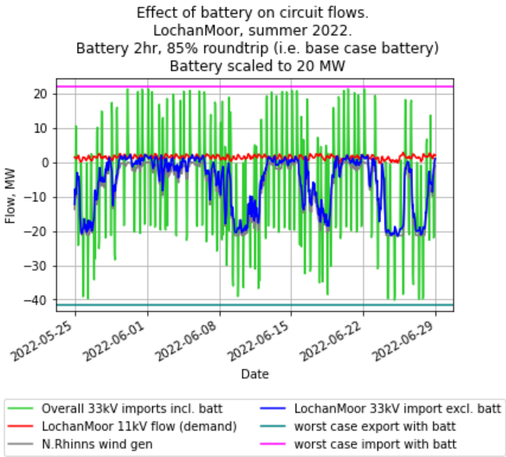
<tr><td>85%</td>
<td>
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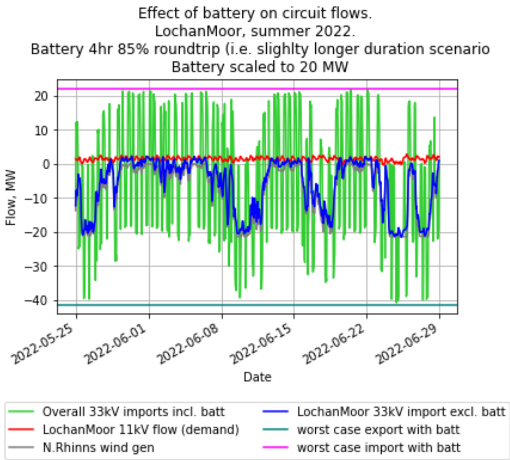
<td>
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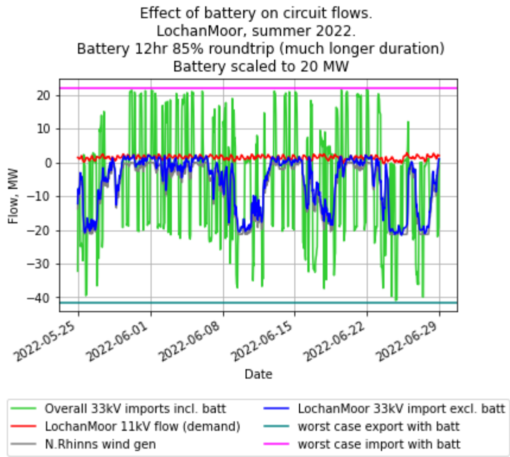
<td>
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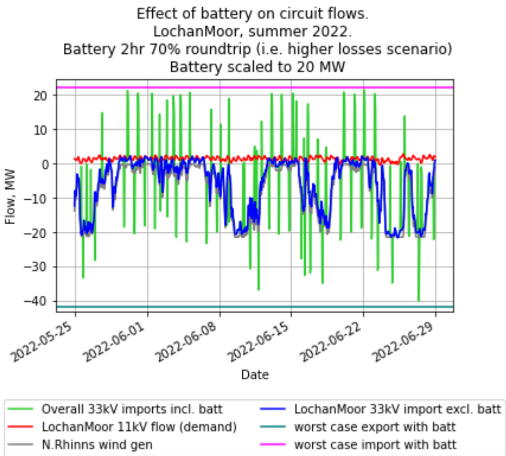
<td>
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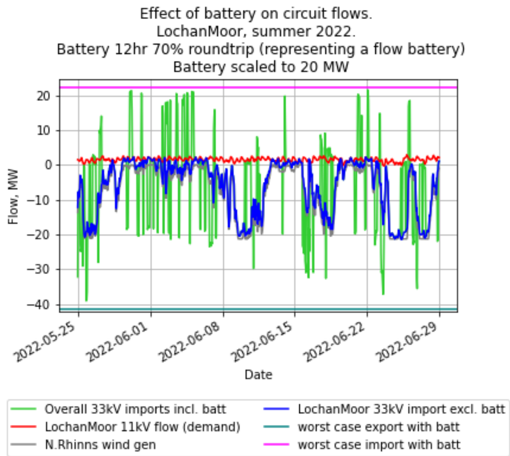
<td>
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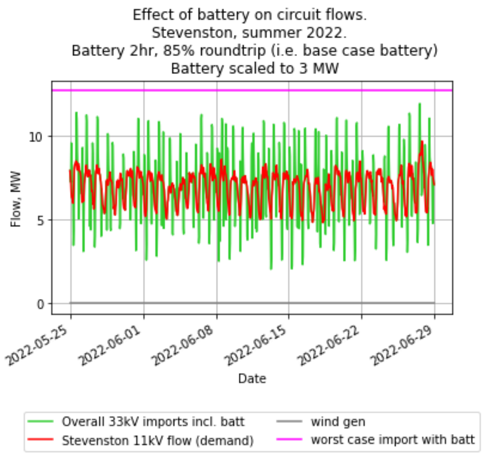
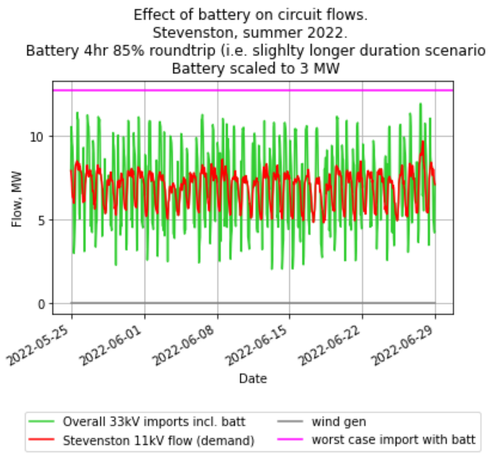
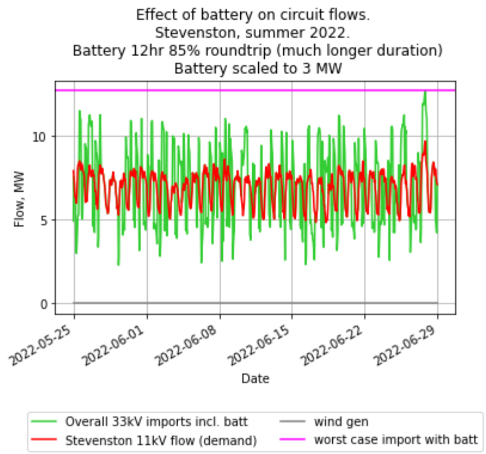
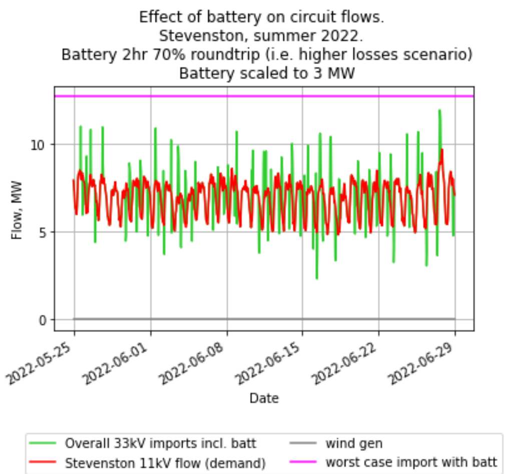
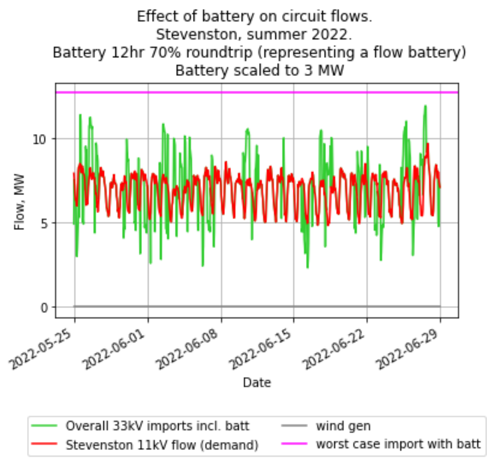
*Annex 13A 5. Summer - 3 MW battery, **Stevenston***

η	2 hour battery	4 hour battery	12 hour battery
85%			
70%		**Not modelled**	

Annex 13B Autumn

*Annex 13B 1. Autumn, 3 MW battery: **Largs***

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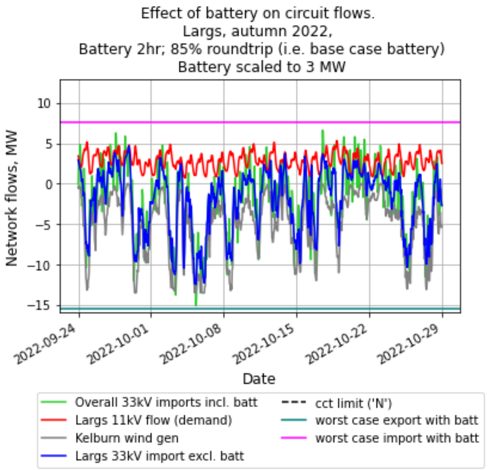
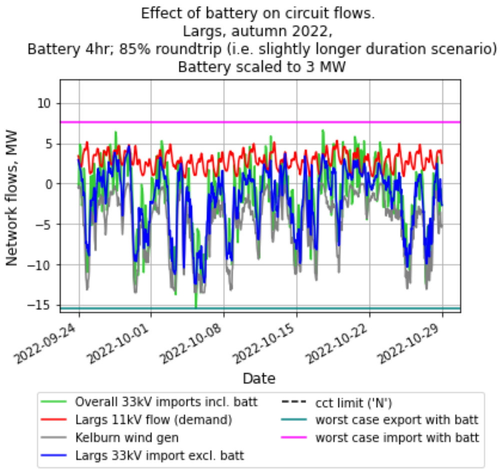
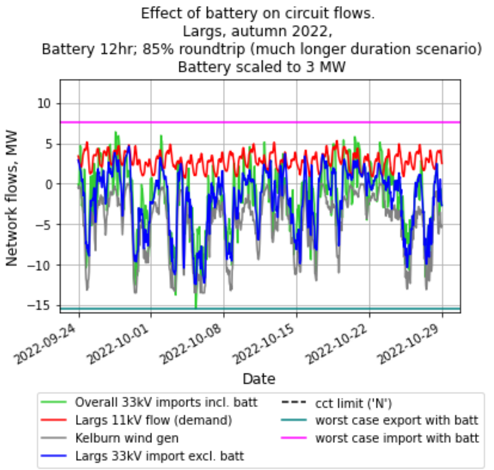
<tr><td>85%</td><td>
</td><td>
</td><td>
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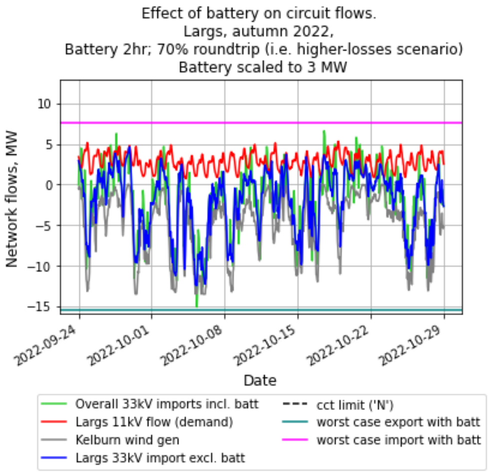
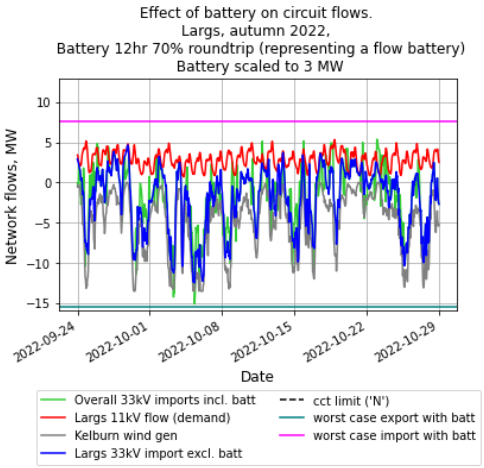
<tr><td>70%</td><td>
</td><td>Not modelled</td><td>
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Annex 13B 2 ***Autumn.*** *5 MW battery,* ***Largs***

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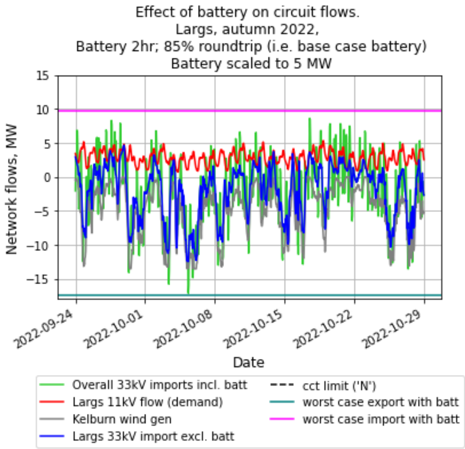

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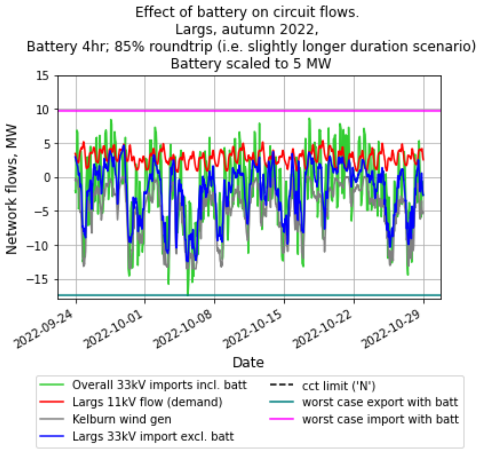

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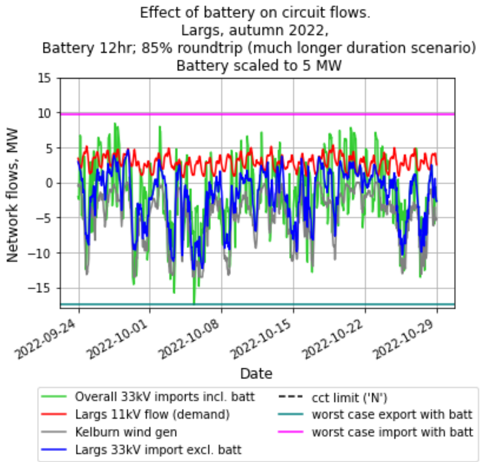

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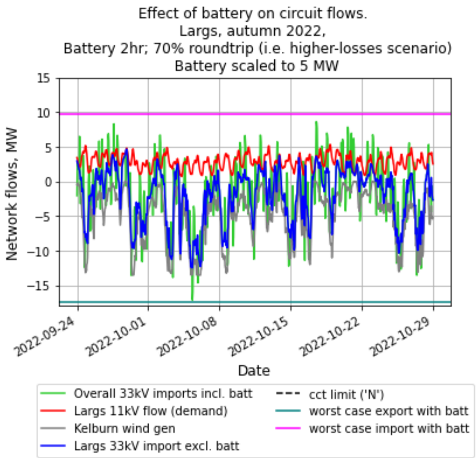
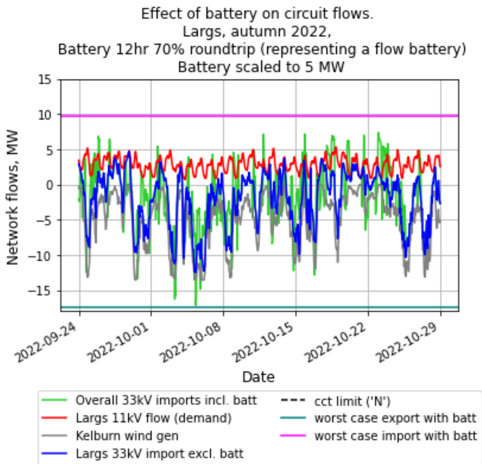
<tr><td>70%</td><td>


</td><td>Not modelled</td><td>


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Annex 13B 3 ***Autumn.*** *20 MW battery,* ***Largs***

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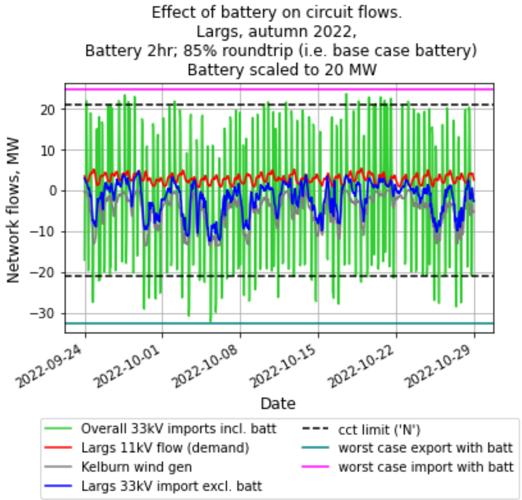
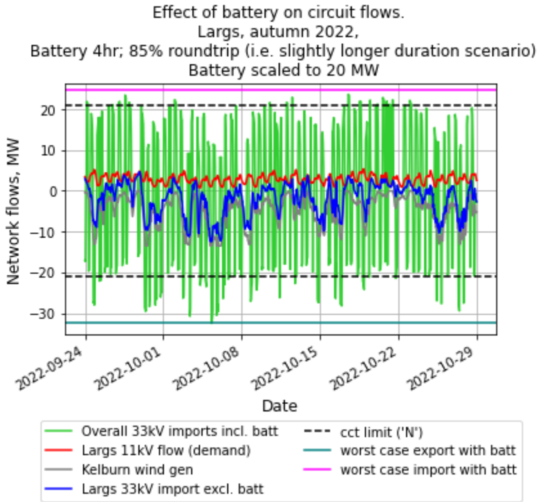
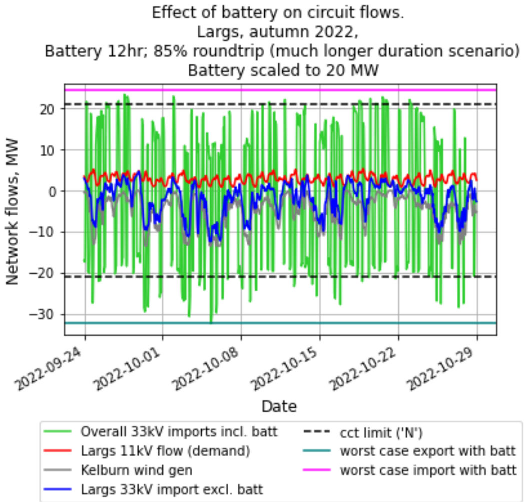
<tr><td>85%</td><td>
</td><td>
</td><td>
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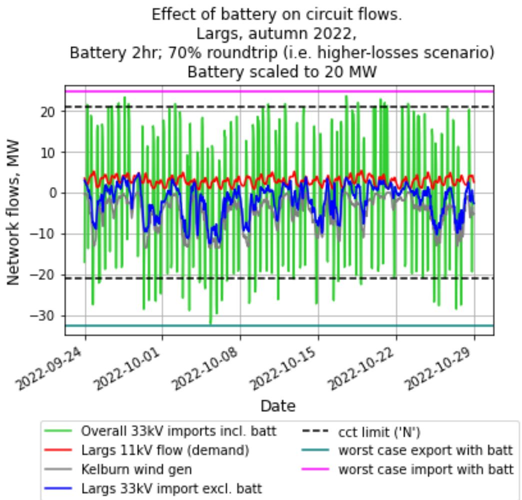
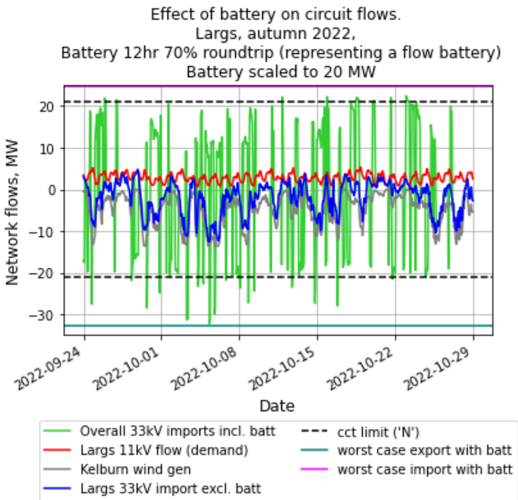
<tr><td>70%</td><td>
</td><td>Not modelled</td><td>
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Annex 13B 4 ***Autumn*** *- 20 MW battery,* ***Lochan Moor***

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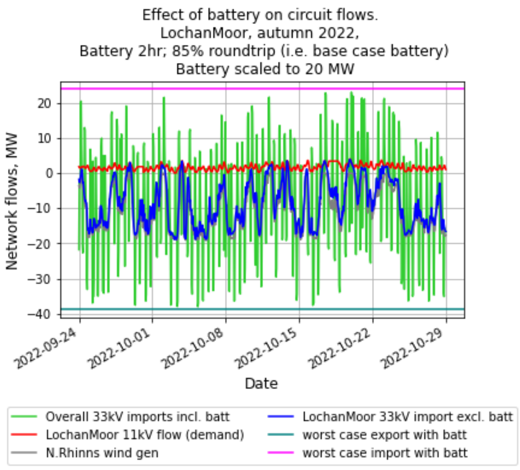
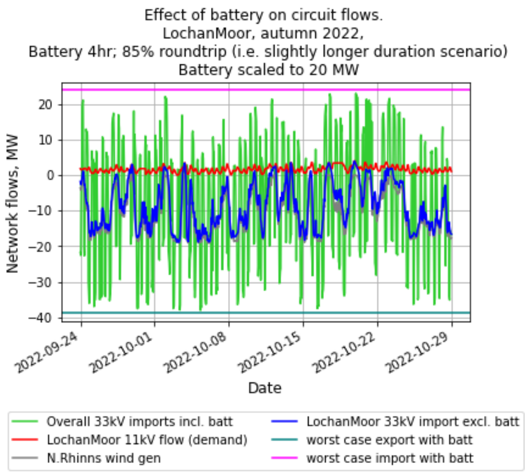
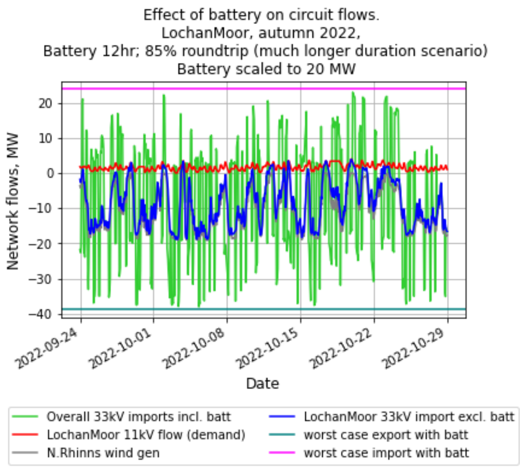
<tr><td>85%</td><td>
</td><td>
</td><td>
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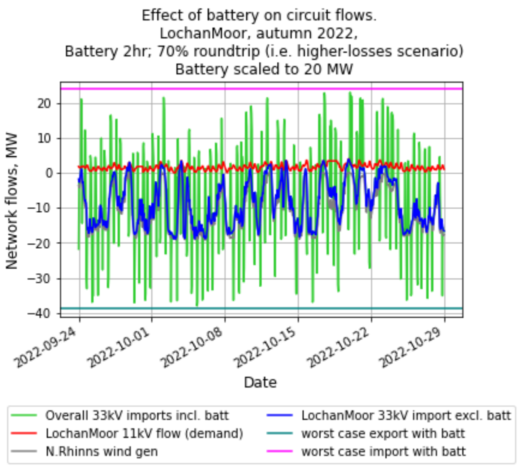
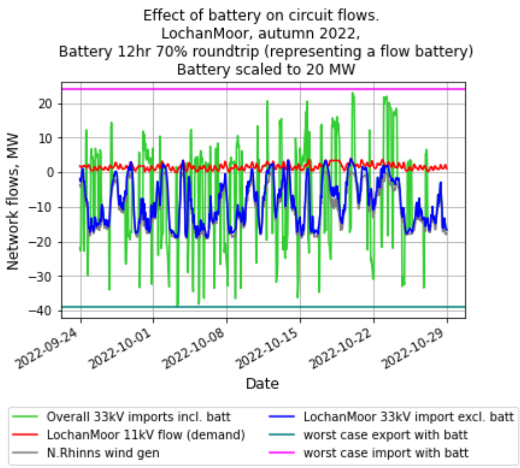
<tr><td>70%</td><td>
</td><td>Not modelled</td><td>
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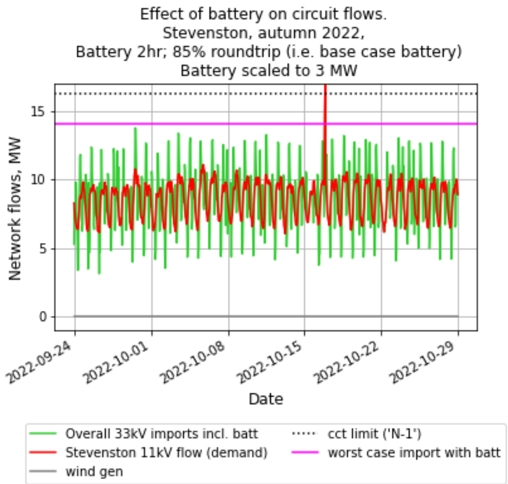
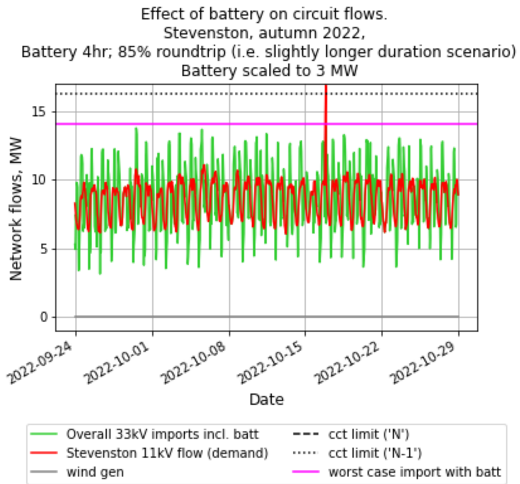
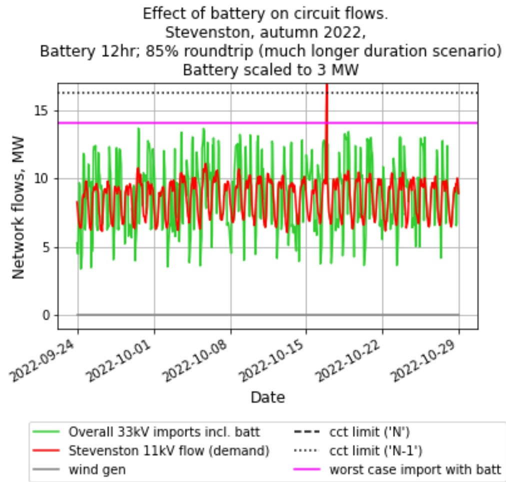
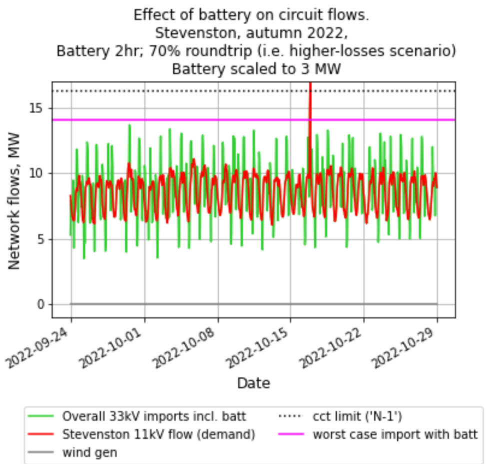
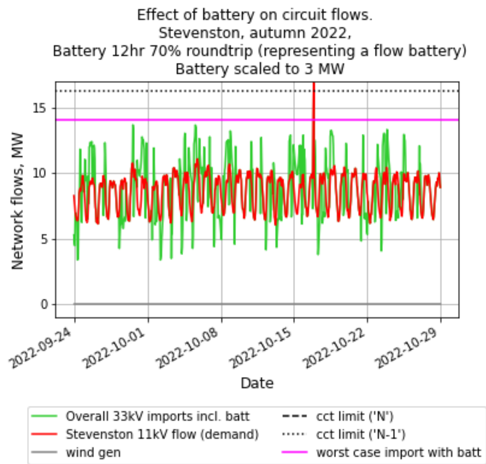
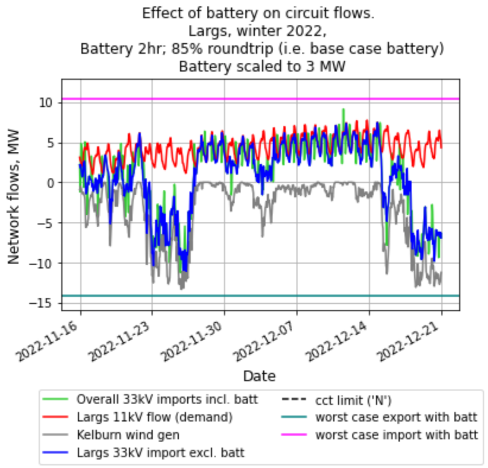
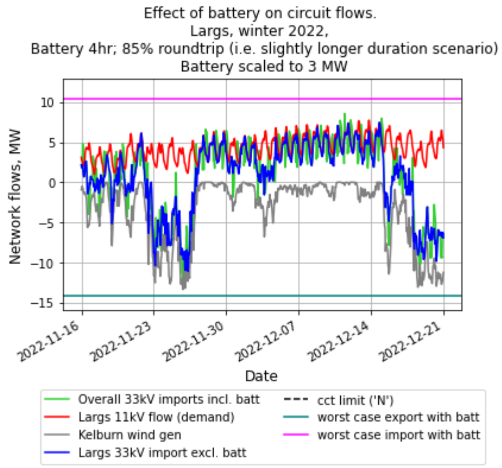
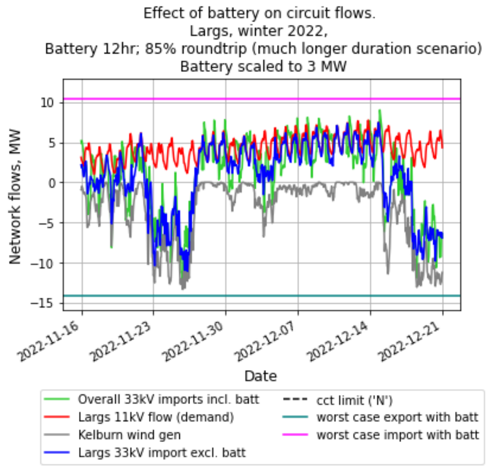
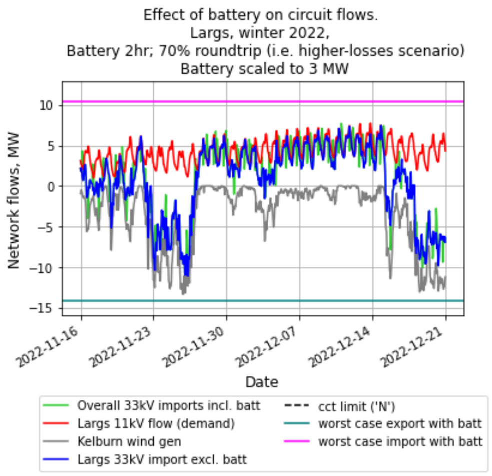
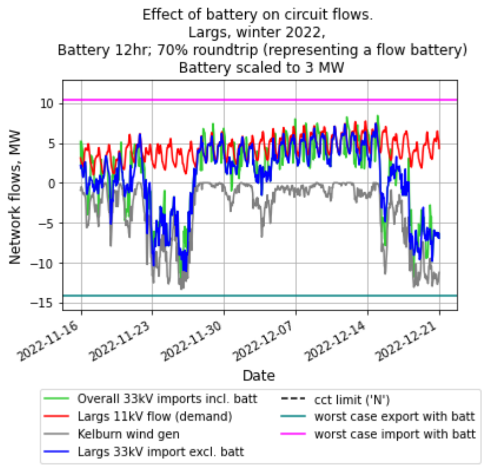
Annex 13B 5 ***Autumn.*** *3 MW battery,* ***Stevenston***

η	2 hour battery	4 hour battery	12 hour battery
85%			
70%		**Not modelled**	

Annex 13C Winter

Annex 13C 1. Winter. 3 MW battery, Largs

η	2 hour battery	4 hour battery	12 hour battery
85%			
70%		**Not modelled**	

Annex 13C 2 ***Winter.*** *5 MW battery,* ***Largs***

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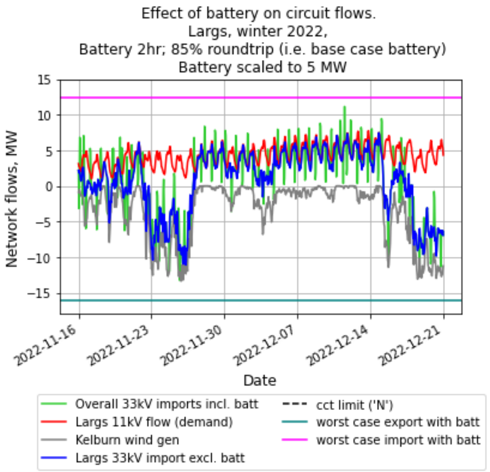
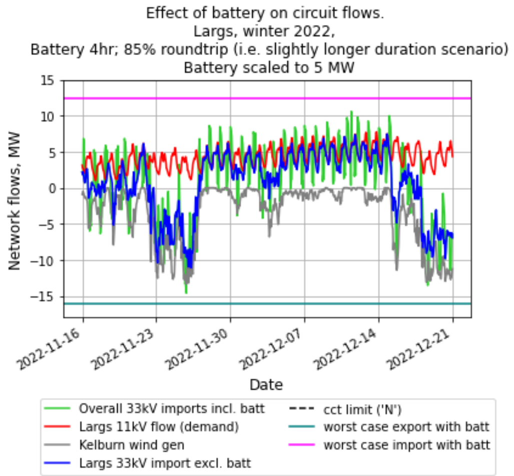
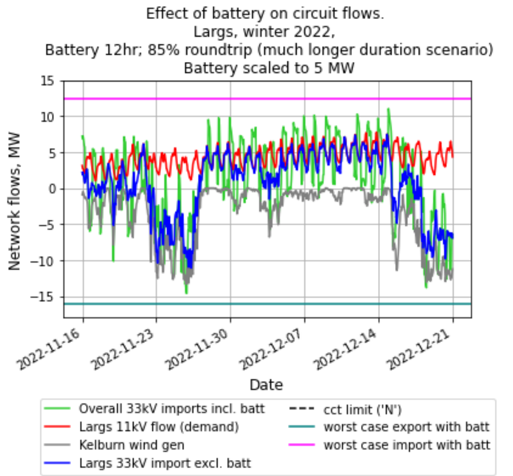
<tr><td>85%</td><td>
</td><td>
</td><td>
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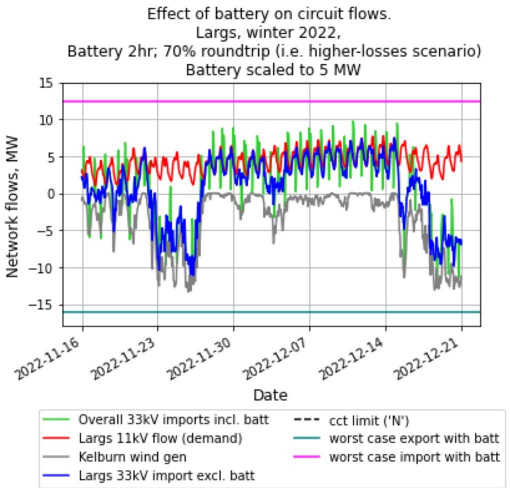
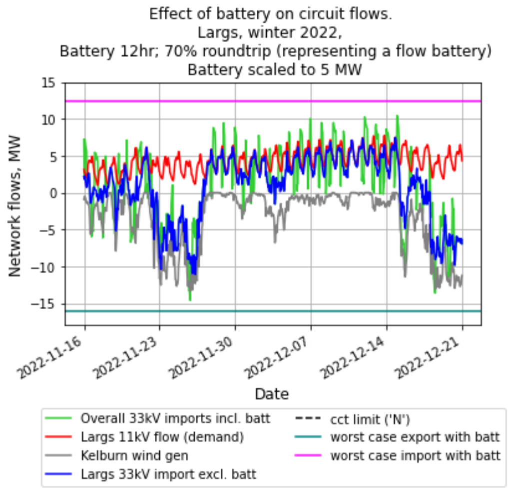
<tr><td>70%</td><td>
</td><td>Not modelled</td><td>
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Annex 13C 3 ***Winter.*** *20 MW battery,* ***Largs***

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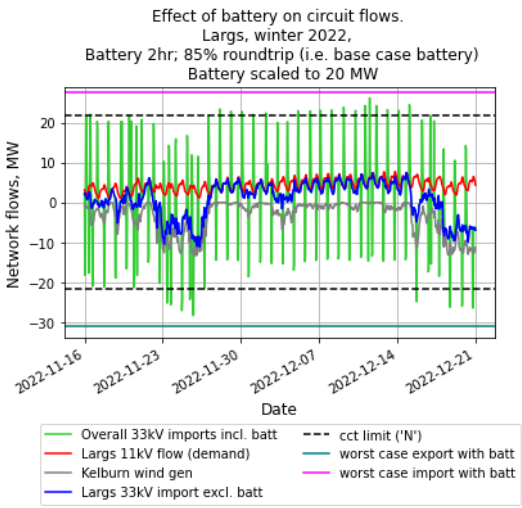
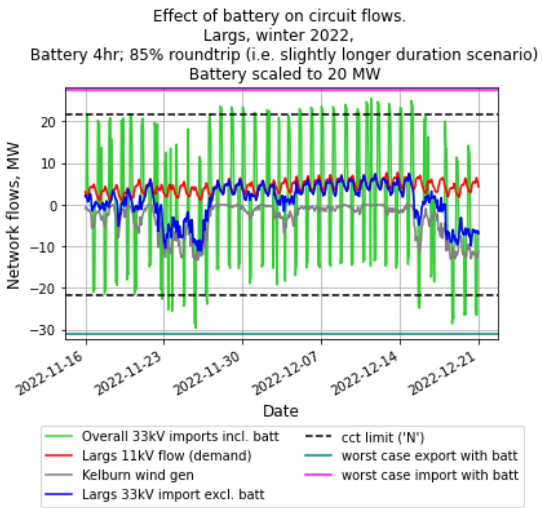
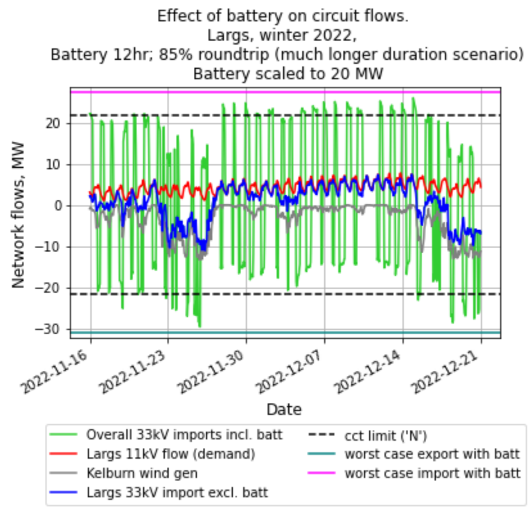
<tr><td>85%</td><td>
</td><td>
</td><td>
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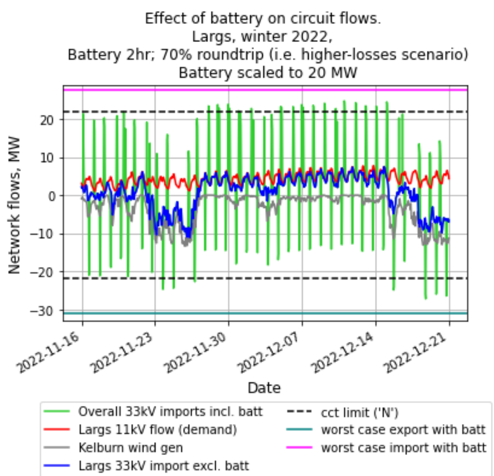
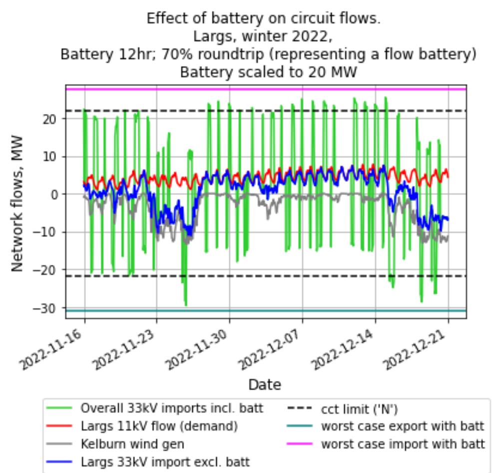
<tr><td>70%</td><td>
</td><td>Not modelled</td><td>
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Annex 13C 4 ***Winter.*** *20 MW battery,* ***Lochan Moor***

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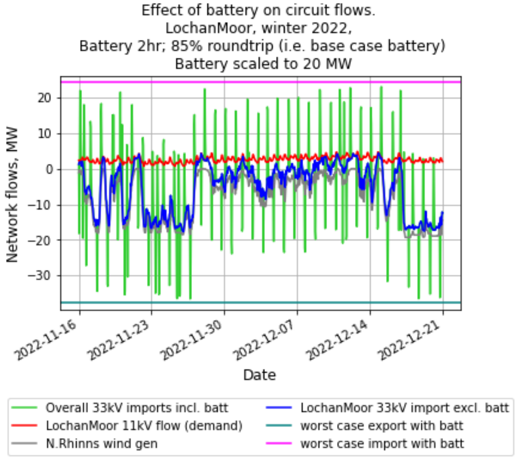

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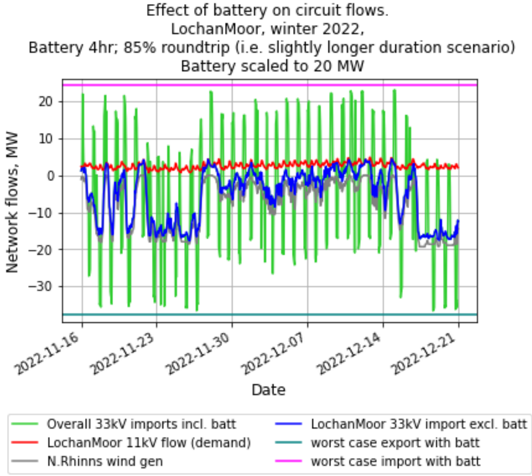

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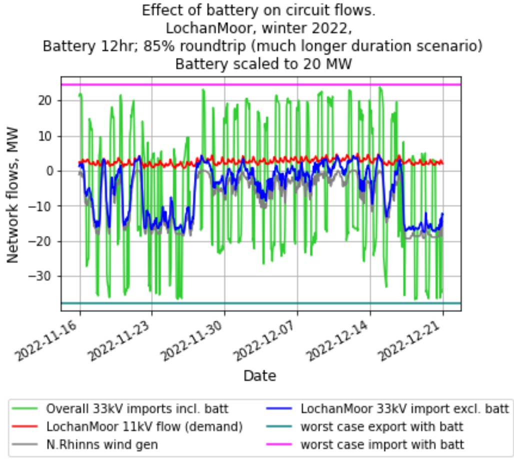

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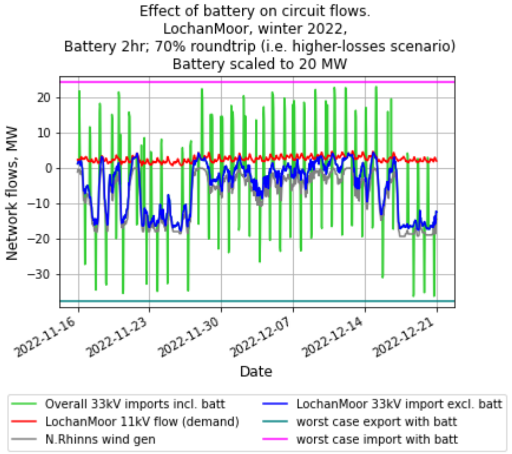

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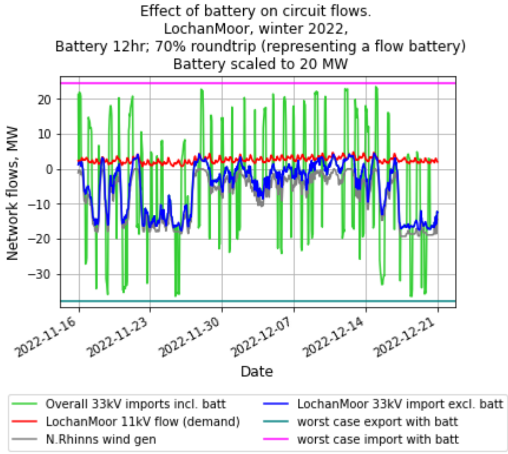

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Annex 13C 5 ***Winter****. 3 MW battery,* ***Stevenston***

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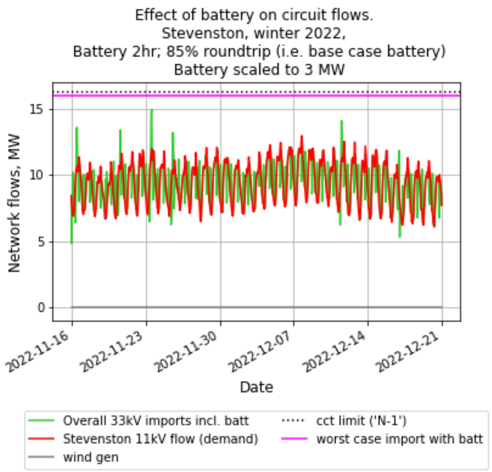
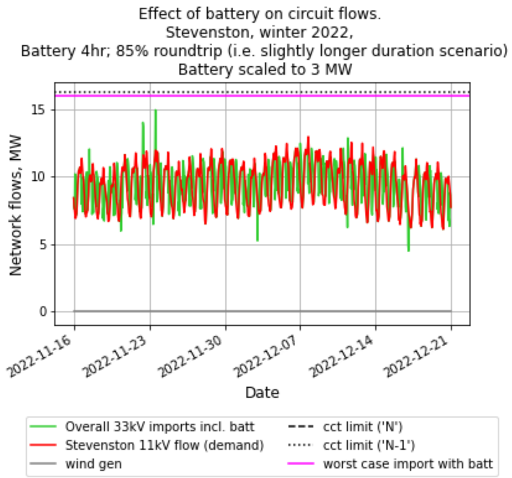
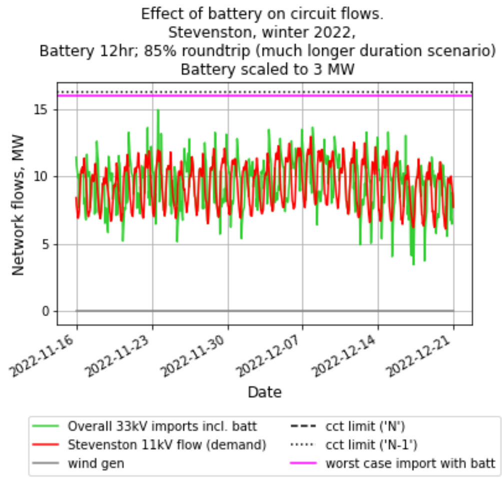
<tr><td>85%</td><td>
</td><td>
</td><td>
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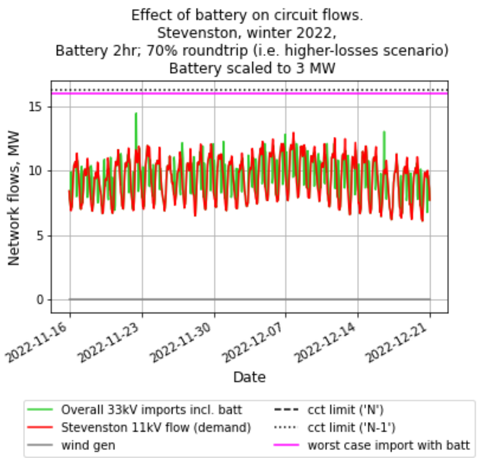
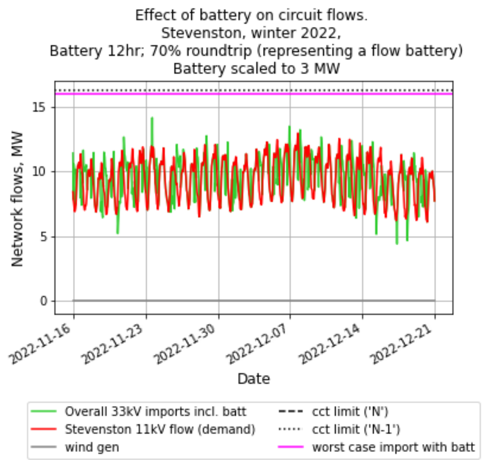
<tr><td>70%</td><td>
</td><td>Not modelled</td><td>
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Annexes to Chapter 7
Projected curtailment costs for distribution-connected batteries with "flexible" ("non-firm") connections

Contents for Chapter 7 Annexes

Figures for Chapter 7 Annexes

Tables for Chapter 7 Annexes

Chapter 7 Annex 1

Defining network headroom in order to size batteries: further details.

This Annex amplifies the calculation of “network headroom” at all 6 case study locations, as described in Chapter 7 section 7.3.2.

Network headroom here is defined as below:

$$minimum\ network\ headroom = \ network\ limit - |maximum\ potential\ network\ flow|$$

For import-dominated circuits:

$$minimum\ network\ headroom = \ network\ limit - |maximum\ demand| + |minimum\ \ generation|$$

For export dominated circuits:

$$minimum\ network\ headroom\ = \ network\ limit - |maximum\ generation| + |minimum\ demand|$$

Here, the “network limit” is taken to be the summer MVA ratings for each circuit. Ratings of transformers were considered too, but in every case, the 33kV circuit summer limit was lower. Values of ‘maximum generation’, ‘maximum demand’, ‘minimum generation’ and ‘minimum demand’ are tabulated in 38 of the thesis, reproduced below (renumbered to Table 123Table 38) for ease of reference.

This annex gives further details of which values were selected, and why.

Which figure to use?

There is a little judgement needed in selecting the most appropriate figures for maximum and minimum demand and generation, for use in setting minimum network headroom in each location. The approach used here is described below.

1. **Which temporal resolution?** Half-hourly (rather than hourly) values for highest and lowest values of generation, demands and network flows were used, to avoid diluting short-duration high and low network flow values.

2. Maximum generation values

The maximum generation values used for Fairlie, Largs, Lochan Moor and Stranraer use BM data for the actual windfarm (for Stranraer) or proxy windfarms (for the other four locations). In all cases, the value selected for use was the highest FPN of the windfarm (with appropriate scaling) during 2022 calendar year. In all cases except for Glenchamber windfarm (connected to Stranraer), the highest output was the same as the windfarm's TEC / ECR capacity. This probably represents a "high wind output scenario": the actual windfarms may not have performed so highly; (several other windfarms in the area never reached their TEC or ECR output; several had periods no or reduced output.

For Armadale, which has four 11kV-connected windfarms, the estimated highest output of 17.91 MW was used. This is obtained by rescaling the data and further recalculations, as described in Annex 7 of Chapter 6.

3. Calculating maximum power flows from generation-dominated locations

At four of the six case study locations, the greatest network flows on the 33kV circuits are exports, from wind generation, rather than demand-led import flows. In Fairlie and Lochan Moor, the power flows are very strongly wind-dominated; in Largs and Armadale, the generation flows are moderated by more significant demand flows, leading to generally lower overall power flows much of the time.

Minimum demand values were used from the datasets after data cleaning, which removed a number of anomalously low demand values presumed to be data errors.

For all locations except for Armadale, the minimum demand and the 5th minimum demand value were within 0.1 MW of each other. The minimum demand figure was used, together with maximum generation to calculate "*abnormal max generation flow*", and the 5th minimum demand was used to calculate "*normal max generation flow*".

In the case of Armadale, the demand values are all synthesised from Monitored Flow readings and rescaled generation. For the vast majority of the three case study periods, this gives a credible demand pattern. However, there were a handful of negative demand values (one of which occurs during the winter case study), or anomalously low positive demand values. It is believed that these are caused by a temporal mismatch between the actual generation from the four small windfarms feeding into Armadale 11kV bus, and SPEN's reported generation dataset – which may be from one or more of the Armadale windfarms, or may be from some other windfarm (and in either case the aggregate output from the windfarms is incorrectly scaled). It was decided to pick a "credible minimum demand value", representing a consistent low demand value. The lowest repeatable and credible demand value was just under 1 MW, the 25th smallest demand value listed, and this is the one selected for use.

4. Maximum demands, and Minimum headroom at demand-dominated circuits

At two of the case study locations, the highest network flows are imports, not exports: Stevenston, which is demand-only, and Stranraer, which has both generation and demand. In both cases, a "representative maximum demand" value was needed. In both these locations, there were a small number of short duration occasions during which the demand was significantly higher than at other times, and occurred at times of year and times of day when maximum flows rarely occur.

The highest values of "monitored flow (i.e. 11kV bus demand) occurring during early evening in winter, in line with general pattern of flows, was selected to represent maximum flow.

Table 122 Normal and abnormal monitored flows at Stranraer and Stevenston

Maximum flow values, dates and times		Stranraer	Stevenston
Highest value of monitored flow ("Abnormal max")	*Value*	*24.756 MW*	*19.791 MW*
	Date	*30 Dec 2022*	*17 Oct 2022*
	Time	*11:30-12:00*	*20:30-21:00*
Representative maximum value of monitored flow, ("Normal max")	Value	11.734 MW	13.354 MW
	Date	9 Feb 2023	18 Jan 2023
	Time	18:00-18:30	17:30-18:00

Two "maximum demand" values were chosen:

(1) the maximum value (used to calculate "*Abnormal max*"); and

(2) a value of maximum demand excluding spikes in demand (used to calculate "*Normal max*"), as illustrated below.

In all cases, the minimum value of generation was 0 MW, which occurred numerous times. So the overall maximum flows were equal to the "abnormal max" and "normal max" demand.

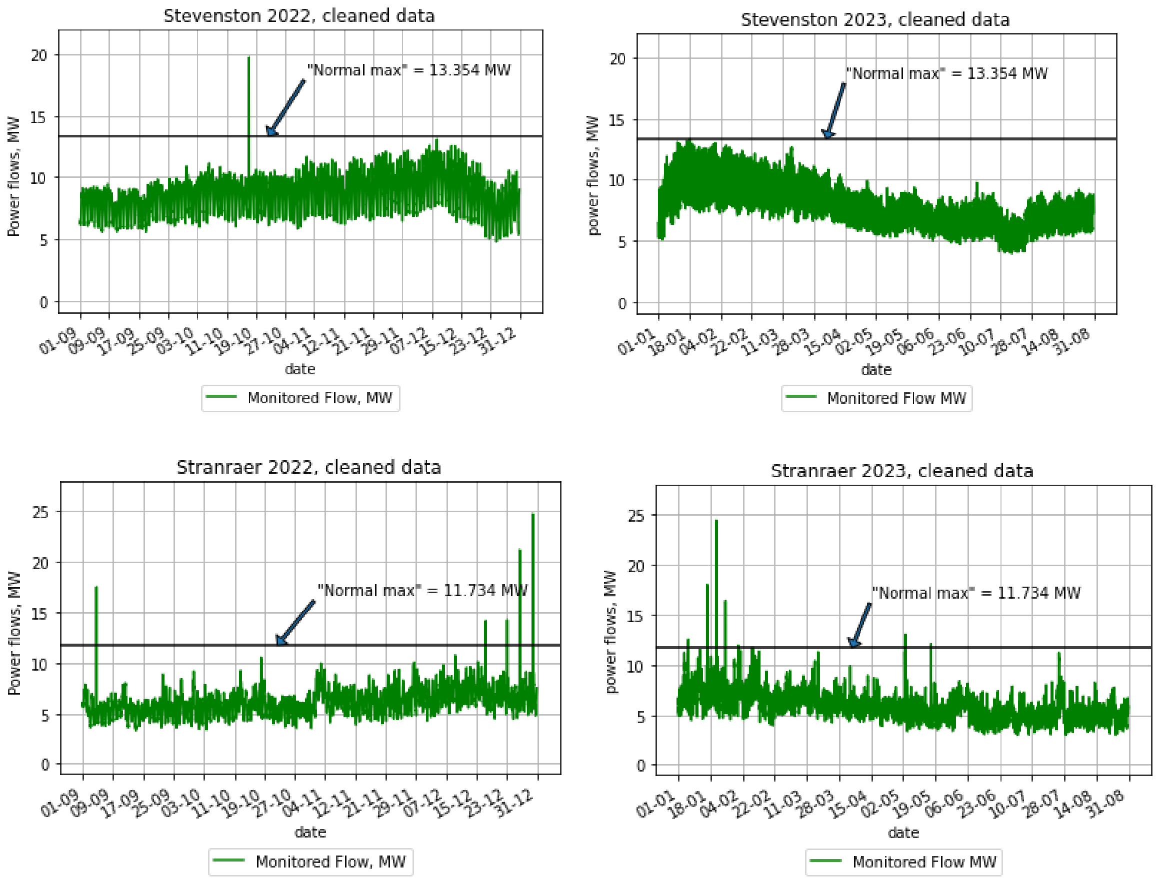


Figure 193 Monitored Flows at Stevenston and Stranraer (after cleaning), 2022 and 2023, showing "normal max" flows

5. In summary: values used.

The values selected to represent maximum circuit flows, "normal max" and "abnormal max" values, are reproduced below in Table 123.

Table 123 Highest and lowest network flow values[112] – used in circuit headroom calculations (This table is shown in thesis Chapter 7, as Table 38).

Place and flow type: Demand (Dem)/ Monitored Flow (MF)	**Demand / Import flows, MW**				**Generation / export flows, MW**				Max flow type	**Largest feasible import or export flow, for use in battery sizing, MW**
	Demand / import		Gen	Max overall import flow	Gen	Demand / import		Max overall export flow		
	Max value	Max demand value used	Min value	"Representative max import flow"	Max value	Min demand value[113]	Min demand value used	"Representative max export flow"		
Fairlie (MF & Dem)	*5.885 ([114])*	1.468	0	*1.50*	14	0.114	0.179	**13.8**	Generation	**13.8**
Largs (MF)	*7.805*	7.71	0	*7.7*	14	0.312	0.346	**13.65**	Generation	**13.65**
Lochan Moor (MF)	*4.889*	4.764	0	*4.8*	22	-0.749	0	**22.0**	Generation	**22.0**
Armadale (Dem)	*13.408*	12.726	0	*12.7*	17.91	-10.8	0.998 ([115])	**16.922**	Generation	**16.922**
Stranraer (MF & Dem)	*24.756*	**11.764**	0	**11.734**	13	2.938	3.013	*9.99*	Demand	**11.734**
Stevenston (MF &Dem)	*19.791*	**13.354**	0	**13.354**	0	3.929	4.079	*-4.1*	Demand	**13.354**

The boxes shaded in green contain the values used in later calculations.

[113] In Lochan Moor, there were some consistent slightly negative values of demand, presumed to be some small embedded generation. In Armadale, negative demand values were presumed to be miscalculations, as described in Chapter 7 Annex 7.
[114] In Fairlie, exceptionally high demands of 1.5-5.9 MW only occurred during several brief occasions during 2023: on 2 May, and between 26 June and 1 July, lasting altogether for less than 4 days over the year. These values were considered anomalous and they were are not used in circuit headroom calculations.
[115] The value at Armadale used is the 25th-smallest value of re-calculated demand. The negative and very low positive values are believed to be from incorrect reported generation figures reported in SPEN's Open Data Portal. More info on rescaling and recalculating of generation and demand at Armadale is given in Chapter 7 Annex 7.

Chapter 7 Annex 2

Effect of network restrictions on battery overall revenues (“N network conditions)

Figure 194 shows how battery overall net revenues increase with battery size (MW capacity), but at a decreasing rate for larger battery sizes.

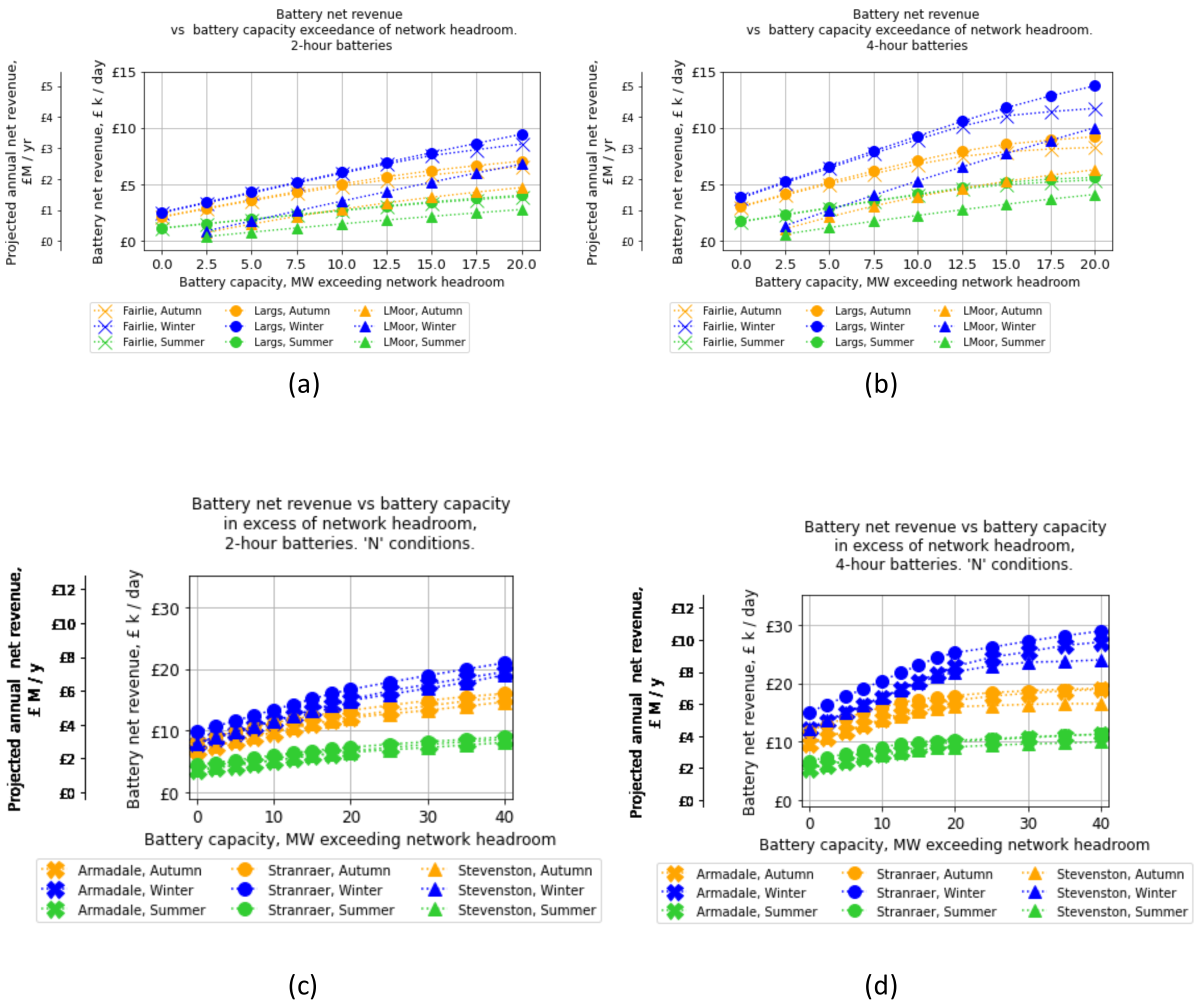
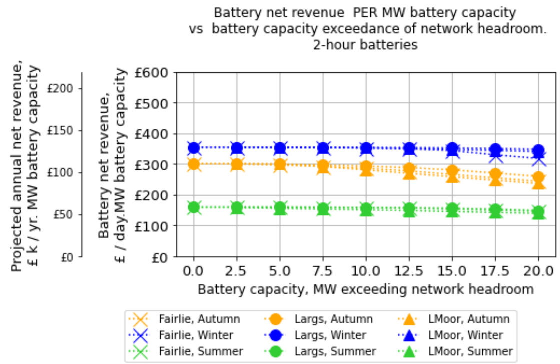


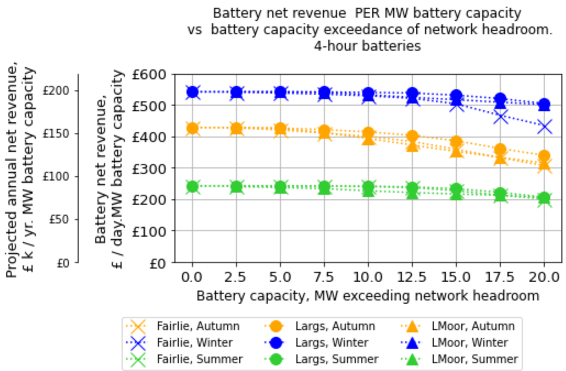
Figure 194 Battery net revenue vs battery capacity (MW) in excess of network headroom. All seasons. (a) Fairlie, Largs, Lochan Moor 2hr batteries, (b) Fairlie, Largs, Lochan Moor, 4 hr batteries; (c) Armadale, Stranraer, Stevenston, 2 hr batteries, (d) Armadale, Stranraer, Stevenston, 4 hr batteries

Battery revenues vary considerably with season, as previously discussed. The differences in overall net revenues between locations at the same season is because the actual battery sizes differ. However, at each season, at smaller battery MW sizes, at all locations, the overall net revenues increase at the same rate with increasing battery capacity, as expected.

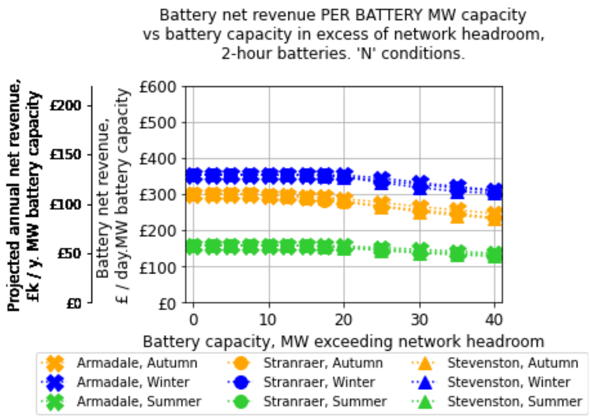
Figure 195 shows how battery revenues per MW of battery capacity – which are, of course, the same at all locations, for each season - are initially unaffected by battery size. However, at larger battery sizes the overall net revenue per MW battery capacity decreases, at all locations.



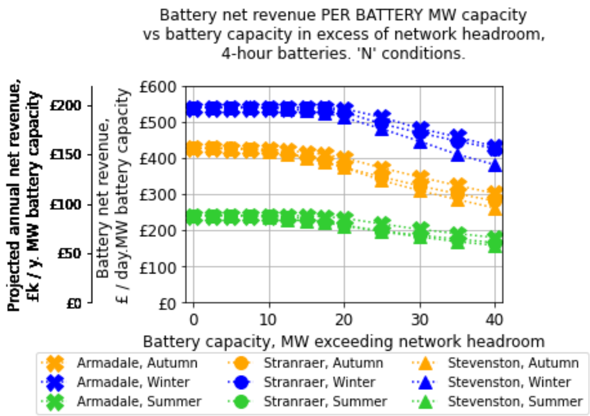
(a)



(b)



(c)



(d)

Figure 195 Battery net revenue per MW battery capacity vs battery capacity (MW) in excess of network headroom. All seasons. (a) Fairlie, Largs, Lochan Moor 2hr batteries, (b) Fairlie, Largs, Lochan Moor, 4 hr batteries; (c) Armadale, Stranraer, Stevenston, 2 hr batteries, (d) Armadale, Stranraer, Stevenston, 4 hr batteries

Figure 196 shows how year-averaged battery overall net revenues vary with battery size. To a first approximation, the values of overall net revenue for battery trades, and their patterns of change with increasing battery capacity, are very similar at all six locations.

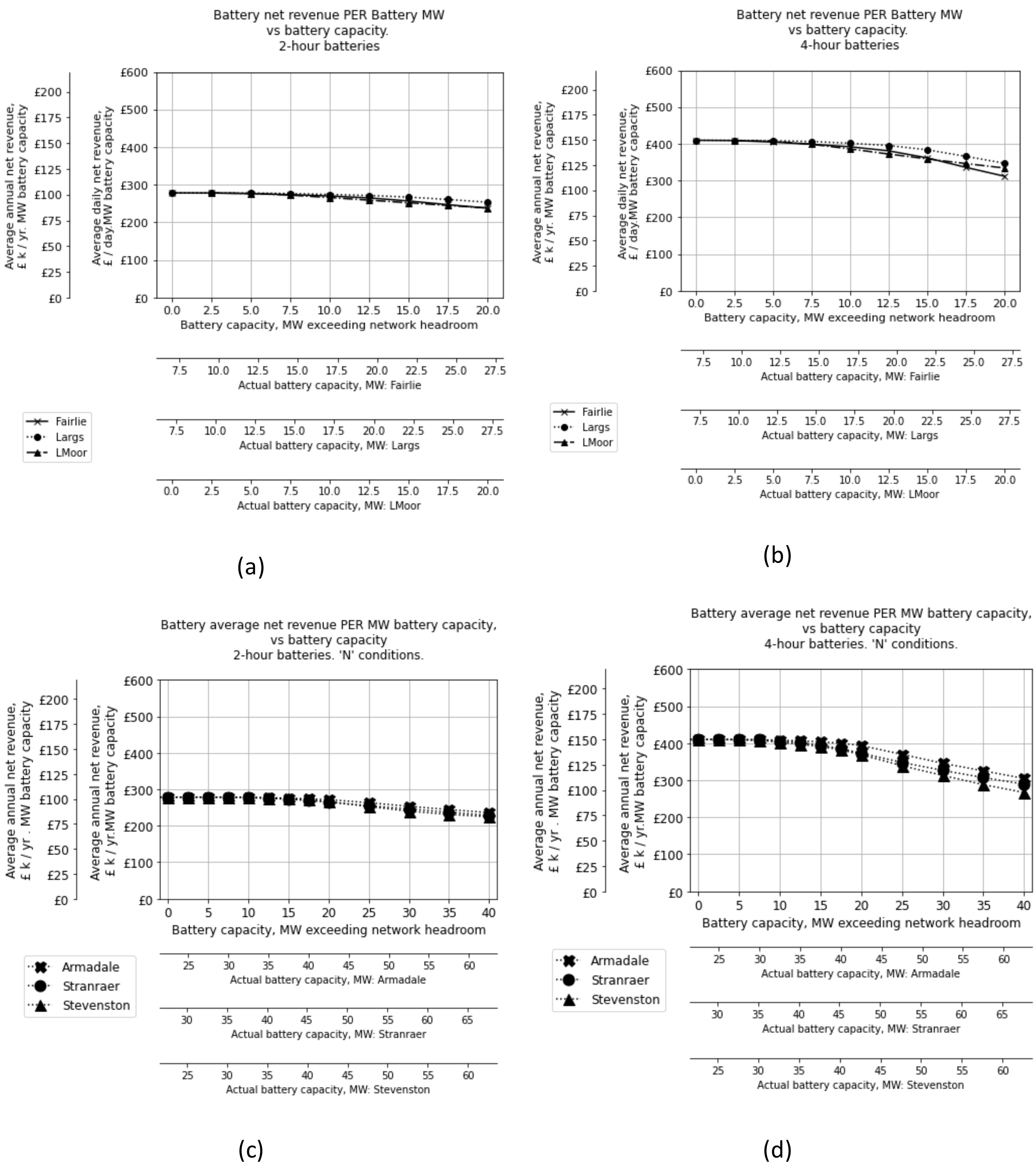


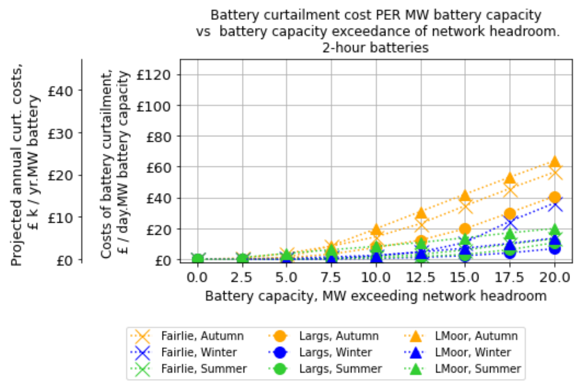
Figure 196 Year-average battery net revenues, daily and annual, per MW battery capacity, vs battery capacity (MW) in excess of network headroom. Averaged over all seasons. (a) Fairlie, Largs, Lochan Moor 2hr batteries, (b) Fairlie, Largs, Lochan Moor, 4 hr batteries; (c) Armadale, Stranraer, Stevenston, 2 hr batteries, (d) Armadale, Stranraer, Stevenston, 4 hr batteries

Chapter 7 Annex 3

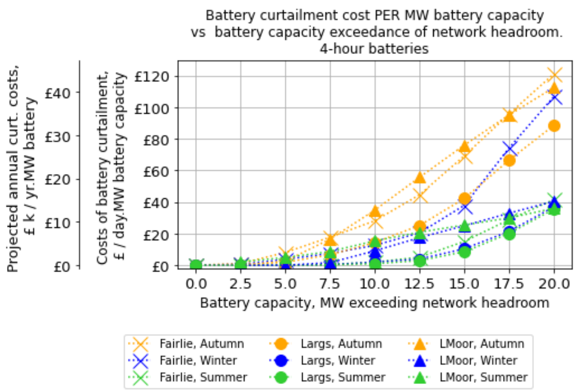
Effect of battery size on curtailment costs (Normal “N” network conditions)

Figure 197 shows the costs of curtailment, caused by network restrictions, vs battery capacity, in excess of network “headroom”.

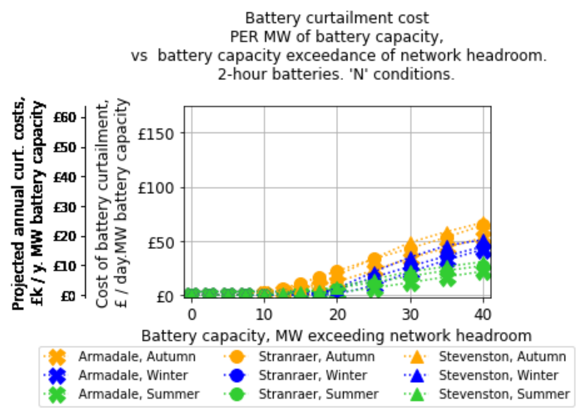
The costs are expressed as costs per day (and projected costs per year) per MW of battery capacity, for each season, location, and for 2-hr and 4-hr batteries.



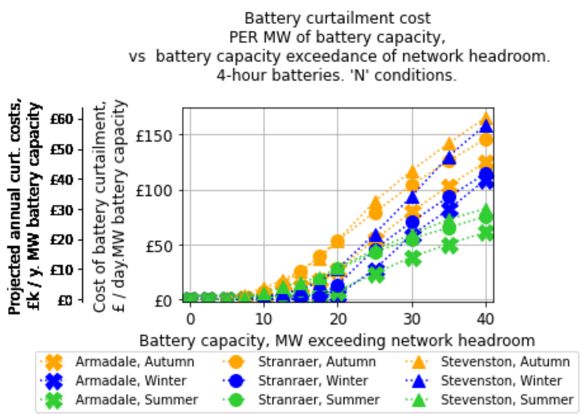
(a)



(b)



(c)



(d)

Figure 197 Curtailment costs per MW battery capacity vs battery capacity (MW) in excess of network headroom. All seasons. (a) Fairlie, Largs, Lochan Moor 2hr batteries, (b) Fairlie, Largs, Lochan Moor, 4 hr batteries; (c) Armadale, Stranraer, Stevenston, 2 hr batteries, (d) Armadale, Stranraer, Stevenston, 4 hr batteries

For comparison, the average daily revenues of a battery on an unrestricted network, at the different seasons, as described in Table 22 in Chapter 4, are tabulated here in Table 124 of this annex.

Table 124 Net revenues for 2-hr and 4hr batteries, for the 3 seasons, on an unrestricted network

	2-hour battery	4-hour battery
Summer	£157	£237
Autumn	£300	£428
Winter	£354	£541

Curtailment costs are expressed as percentage of battery net revenue for each season, in Figure 198. The proportional summer curtailment costs appear to be relatively high, compared to those displayed in Figure 197. This difference is because the base-case battery overall revenues are considerably lower in summer than for the other two seasons.

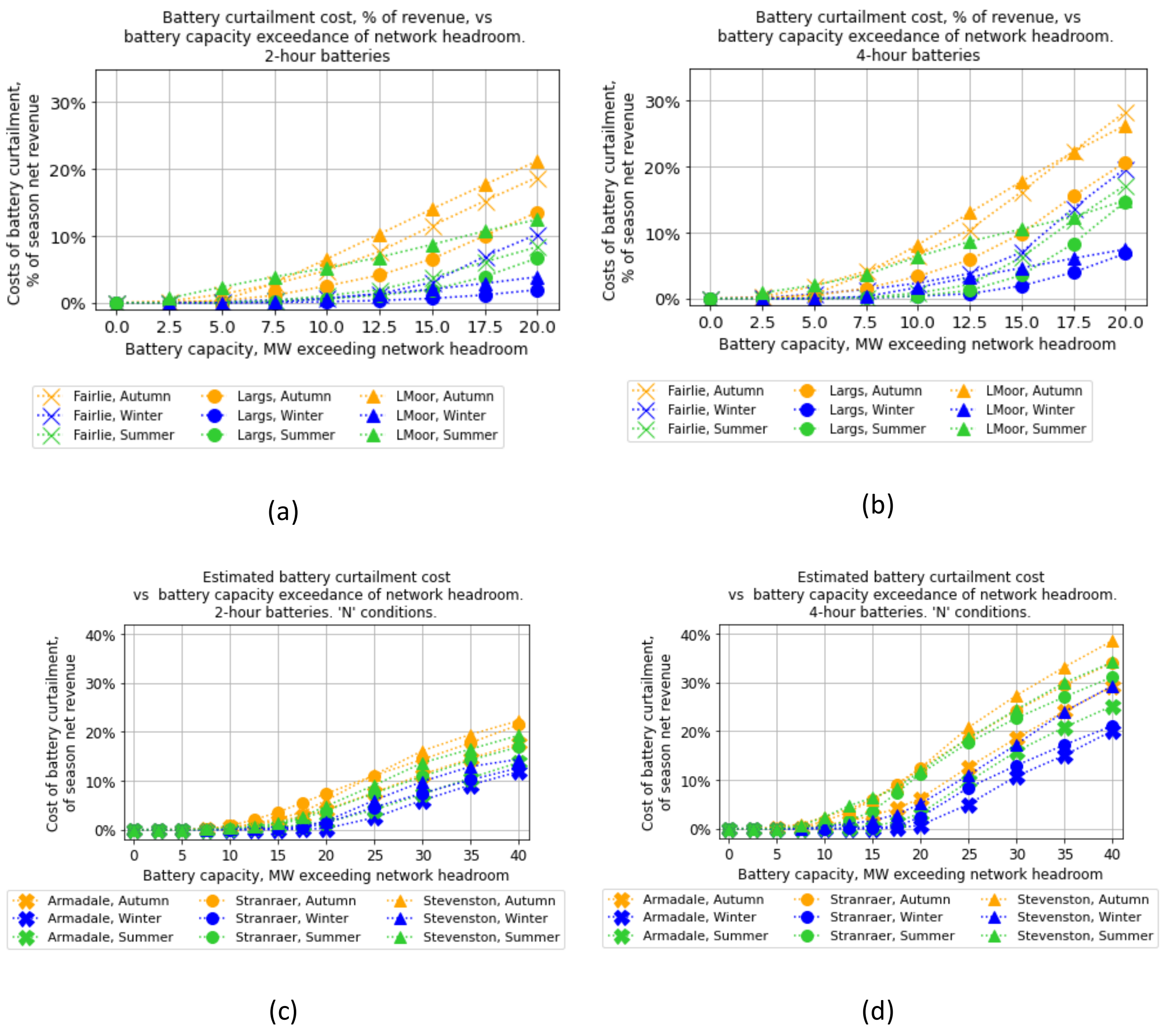


Figure 198 Curtailment costs, as a percentage of revenue over the season on an unrestricted network, vs battery capacity (MW) in excess of network headroom. All seasons. (a) Fairlie, Largs, Lochan Moor 2hr batteries, (b) Fairlie, Largs, Lochan Moor, 4 hr batteries; (c) Armadale, Stranraer, Stevenston, 2 hr batteries, (d) Armadale, Stranraer, Stevenston, 4 hr batteries

Year average absolute curtailment costs (£/day and £/year) for all locations, vs battery capacity in excess of network headroom, are shown in Figure 199. Year-average curtailment costs per MW of battery capacity, vs battery capacity, are shown in Figure 200. Year average proportional curtailment costs, as a percentage of annual average revenue, are shown in Figure 201.

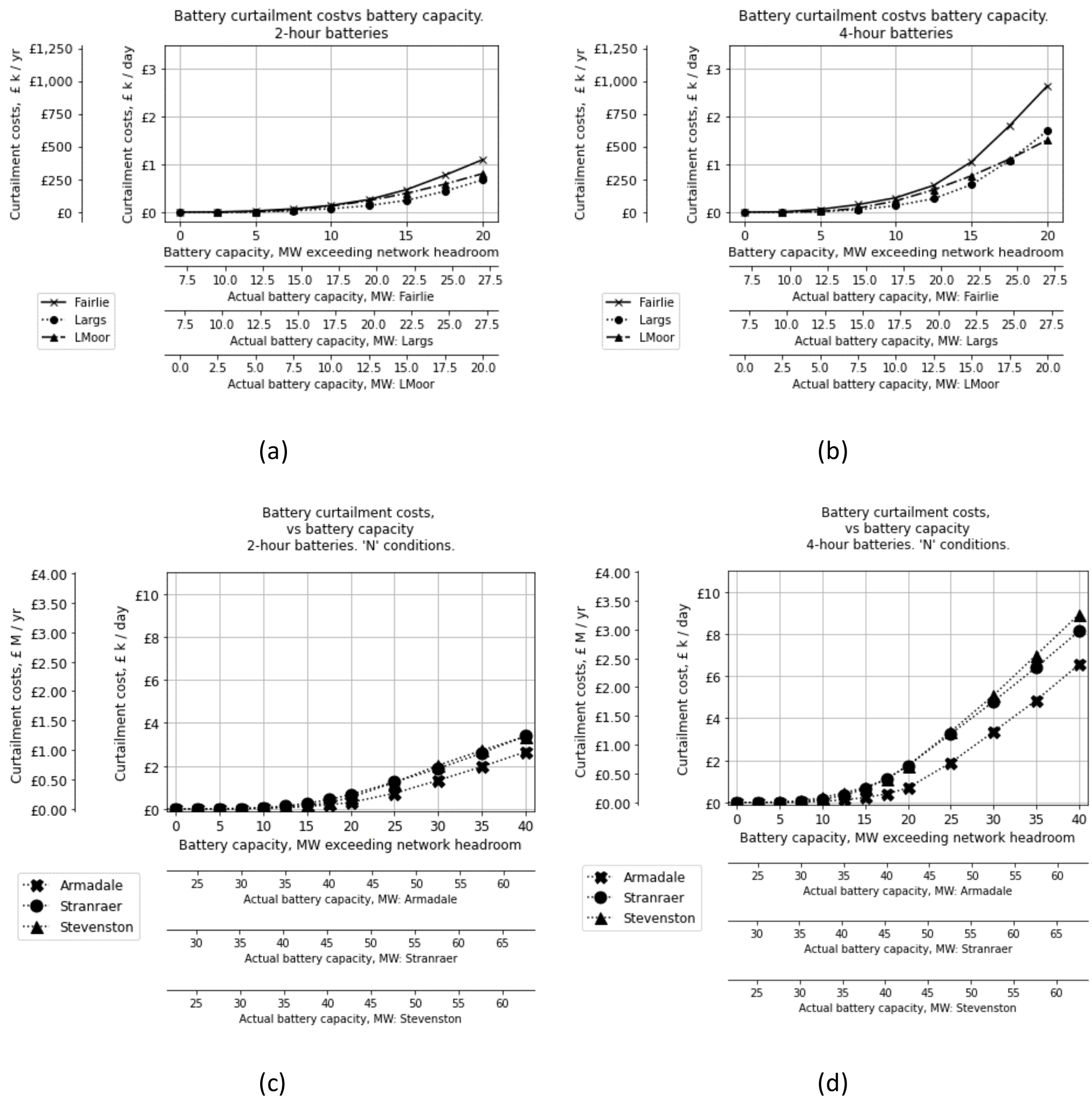


Figure 199 Battery absolute curtailment costs, year average, vs battery capacity. (a) Fairlie, Largs and Lochan Moor, 2-hr batteries, (b) Fairlie, Largs and Lochan Moor, 4-hr batteries; (c) Armadale, Stranraer and Stevenston, 2-hr batteries, (d) Armadale, Stranraer and Stevenston, 4-hr batteries

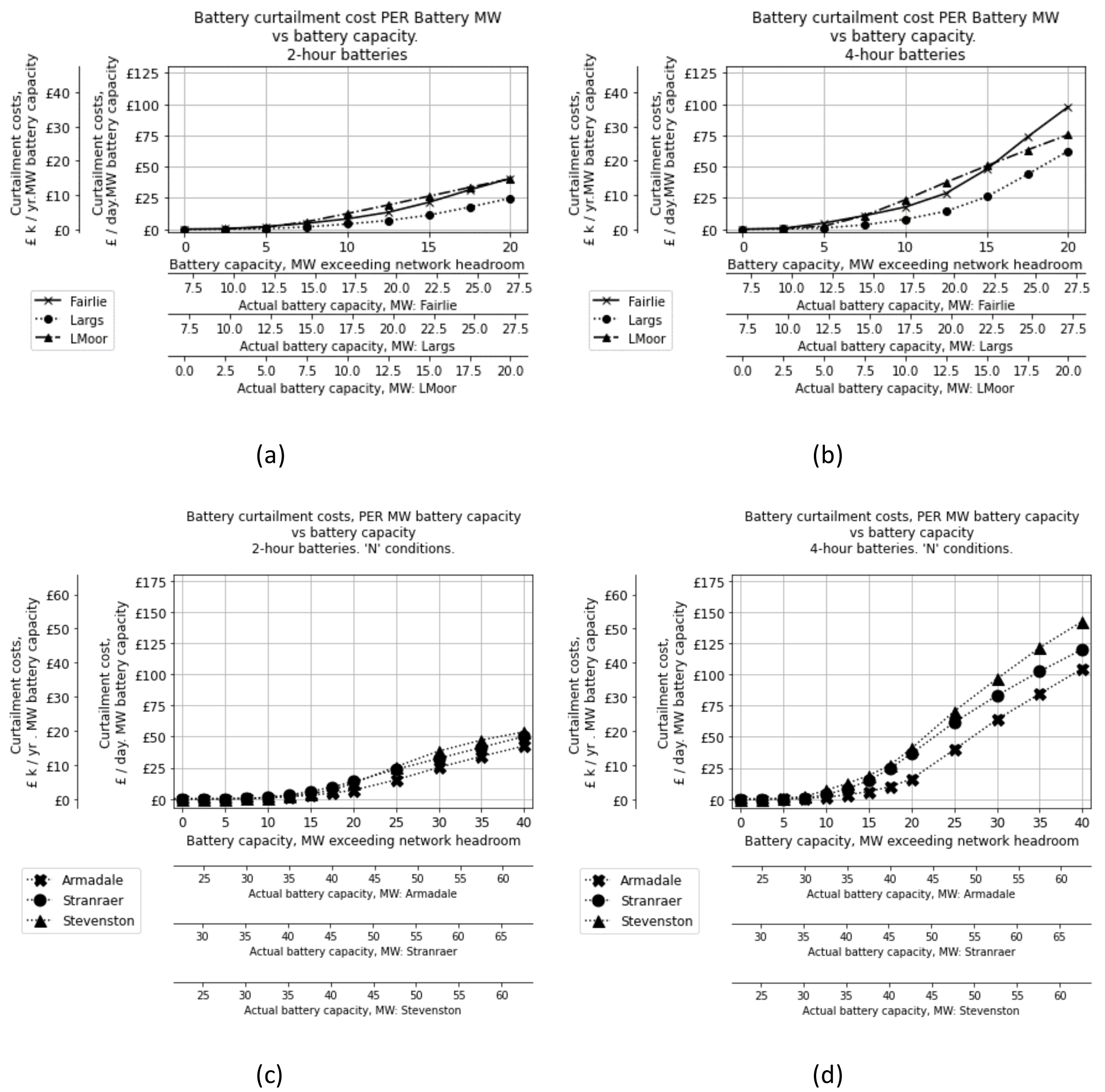
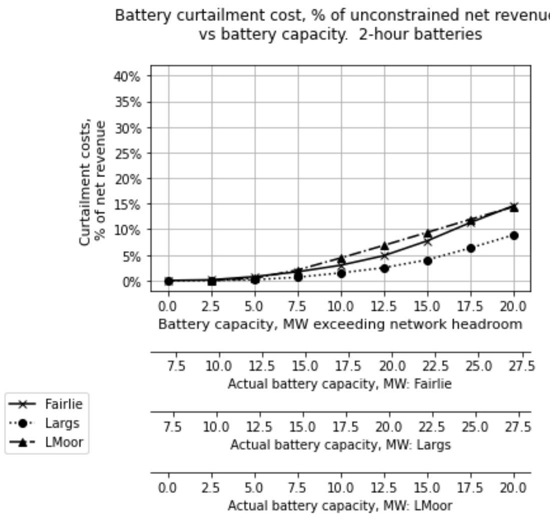
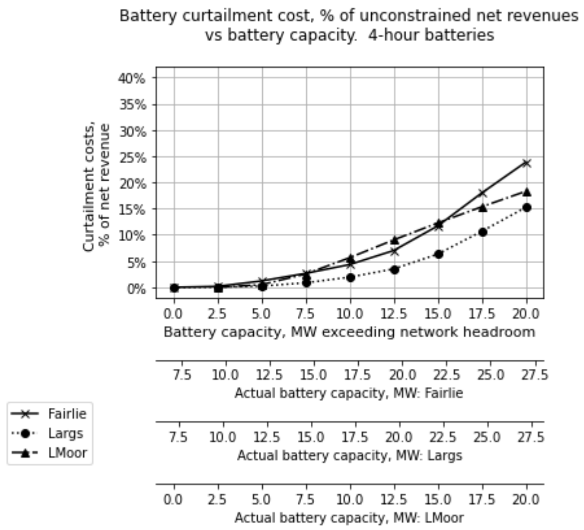


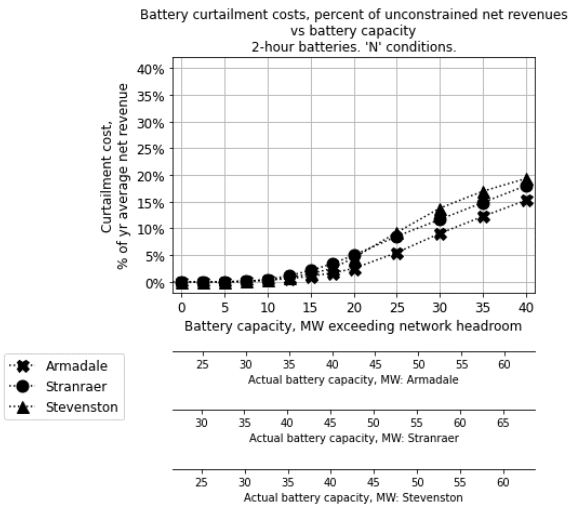
Figure 200 Battery curtailment costs per MW of battery capacity, year average, vs battery capacity. (a) Fairlie, Largs and Lochan Moor, 2-hr batteries, (b) Fairlie, Largs and Lochan Moor, 4-hr batteries; (c) Armadale, Stranraer and Stevenston, 2-hr batteries, (d) Armadale, Stranraer and Stevenston, 4-hr batteries



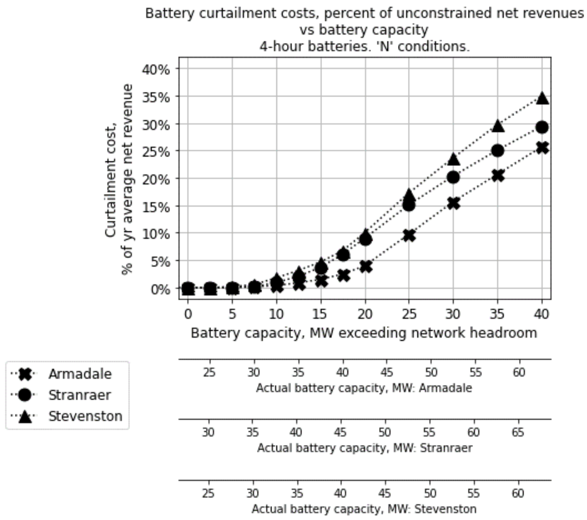
(a)



(b)



(c)



(d)

Figure 201 Average battery curtailment costs, as a percentage of year-average net revenues (without any constraints), vs battery capacity. (a) Fairlie, Largs and Lochan Moor, 2-hr batteries, (b) Fairlie, Largs and Lochan Moor, 4-hr batteries; (c) Armadale, Stranraer and Stevenston, 2-hr batteries, (d) Armadale, Stranraer and Stevenston, 4-hr batteries

Chapter 7 Annex 4

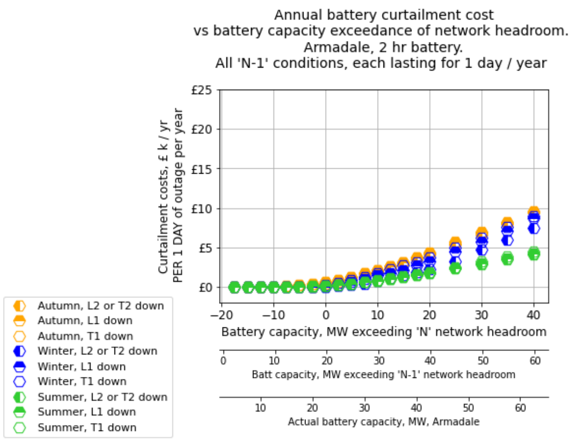
Abnormal circuit conditions. Effect of battery size on battery curtailment costs, under "N-1" conditions.

"N-1" conditions were considered for the three 2-feeder locations (Armadale, Stranraer and Stevenston).

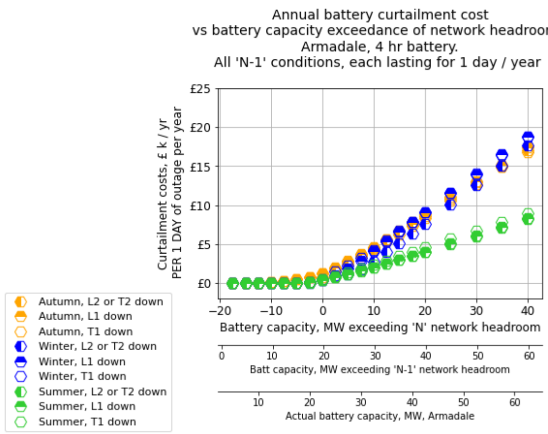
Scenarios for three different types of "N-1" condition were investigated (L2 or T2 not working; L1 not working, and T1 not working), as described in Chapter 7, section 7.3.3.

Figure 202 shows the variation of curtailment cost – of 1 day of reduced revenue because of network conditions - with battery MW capacity. Each plot shows one location, one battery duration, and the three types of 'N-1' condition, for the three seasons. The curves show a broadly similar pattern to the plots under 'N' conditions: for the smallest batteries, initially no cost, with costs beginning to rise for batteries of headroom around 10-20 MW above the prevailing network headroom conditions – which are approximately 20 MW smaller than under "N" conditions.

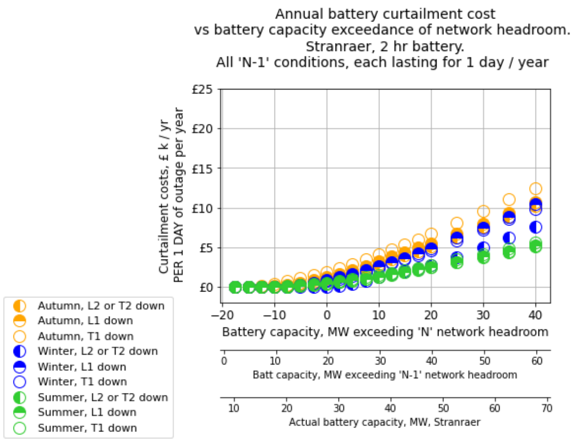
Generally, the costs of the three types of 'N-1' conditions are similar to one another, in some cases identical. For larger batteries, the curtailment costs of different network conditions diverge in some locations and seasons.



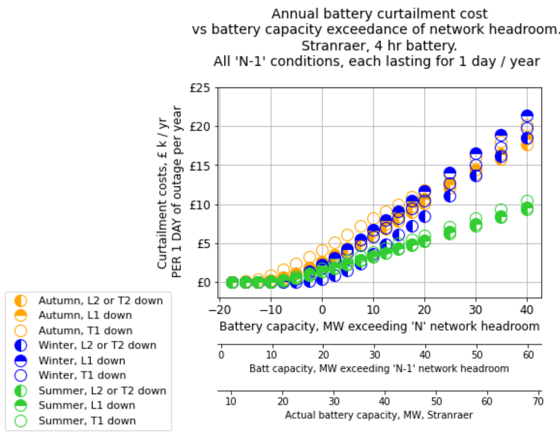
(a)



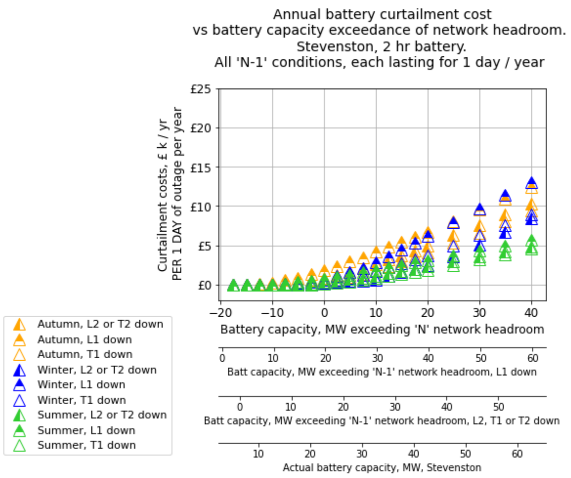
(b)



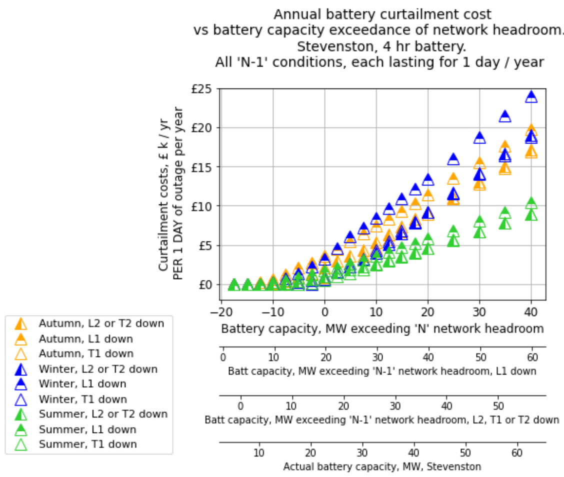
(c)



(d)



(e)



(f)

Figure 202 Cost of 1 day of curtailment under 3 different “N-1” conditions, vs battery capacity, all seasons. (a) Armadale, 2-hr battery; (b) Armadale, 4-hr battery; (c) Stranraer, 2-hr battery; (d) Stranraer, 4 hr battery; (e) Stevenston, 2-hr battery; (f) Stevenston, 4-hr battery.

Differences between curtailment costs of different "N-1" network conditions: L1 inoperable, compared with L2 or T2 inoperable

For all locations, the following results are observed:

$$cost\ of\ curtailment(L1\ unavailable) \geq cost\ of\ curtailment(L2\ or\ T2\ unavailble) \quad \text{(A7.1)}$$

At every location: $$T1_{location} = T2_{location} \quad \text{(A7.2)}$$

The transformers do not have seasonal ratings, but the OHLs do have different seasonal limits.

For Armadale and Stranraer: $$L1_{location,season} = L2_{location,season} \quad \text{(A7.3)}$$

However, for Stevenston: $$L1_{season} > L2_{season} \quad \text{(A7.4)}$$

Section 7.3.3 of Chapter 7 state the equations of network capacity under various network conditions.

N-1 scenario 1: Network capacity available to battery when L2 or T2 is unavailable:

For all three locations, in the event of Line 2 or Transformer 2 being unavailable, the following equations apply, as stated in Section 7.3.3 in Chapter 7:

$$network\ capcity\ (\text{N-1 (line2 unavailable)}, exporting, t) = L1_{season} + D_t - G_t \quad \text{(A7.5) (7.25)}$$

$$network\ capcity\ (\text{ N-1\_line2 unavailable}, importing, t) = L1_{season} - D_t + G_t \quad \text{(A7.6) (7.26)}$$

In the case of Stevenston, G(t) = 0 (A7.7)

N-1 scenario 2: Network capacity available to battery when L1 is unavailable

$$\begin{aligned} &network\ capacity\ (\text{Armadale, N-1 (line1 unavailable)}, exporting, t) \\ &= \min(T1, \quad (T2 + D_t - G_t), \quad (L2_{season} + D_t - G_t)\ ) \end{aligned} \quad \text{(A7.8) (7.27)}$$

$$\begin{aligned} &network\ capcity\ (\text{Armadale, N-1 (line1 unavailable)}, importing, t) \\ &= \min(T1, \quad (T2 - D_t + G_t), \quad (L2_{season} - D_t + G_t)\ ) \end{aligned} \quad \text{(A7.9) (7.28)}$$

In the case of Stranraer, because of the different network topology, slightly different equations apply:

$$\begin{aligned} &\mathit{network\ capacity}\ (\text{Stranraer, N-1(line1 unavailable)}, \mathit{exporting}, t) \\ &= -G_t + \min(T1, \quad (T2 + D_t), \quad (L2_{season} + D_t)\,) \end{aligned} \tag{A7.10}$$
(7.29)

$$\begin{aligned} &\mathit{network\ capacity}\ (\text{Stranraer, N-1(line1 unavailable)}, \mathit{importing}, t) \\ &= +G_t + \min(T1, \quad (T2 - D_t), \quad (L2_{season} - D_t)\,) \end{aligned} \tag{A7.11}$$
(7.30)

N-1 scenario 3: Network capacity available to battery when T1 is not available

For Armadale and Stevenston:

$$\mathit{network\ capacity}\ (\ \text{N-1(Transformer1 unavailable)}) = L1_{season} \tag{A7.12}$$
(7.31)

For Stranraer:

$$\mathit{network\ capacity}\ (\ \text{N-1(Transformer1 unavailable)}, \mathit{exporting}, t) = L1_{season} - G_t \tag{A7.13}$$
(7.32)

$$\mathit{network\ capacity}\ (\ \text{N-1(Transformer1 unavailable)}, \mathit{importing}, t) = L1_{season} + G_t \tag{A7.14}$$
(7.33)

Some observations

Thus, during Line 1 unavailability, network capacity available for battery actions is limited by the capacity of T1, rather than the capacity of the feeder, under some conditions. These conditions are: battery exports at times of net demand from the 11kV bus, or for Armadale, battery imports at times of net generation from the 11kV bus. For Armadale and Stevenston, this occurred at batteries of greater capacity than T1; for Stranraer, it occur when the combined capacity of the battery and wind exports exceeded the capacity of T1.

For Stevenston, the difference in capacity between L1 and L2 increases the difference in curtailment costs between the two scenarios.

Differences between curtailment costs of different "N-1" network conditions: T1 inoperable, compared with the other scenarios

At Armadale and Stevenston, for most battery sizes and over most seasons,

$$curtailment\ costs_{battery\ alone\ \ accesses\ L1} \approx curtailment\ cost_{battery\ and\ network\ demands\ \&\ generation\ access\ L1} \qquad (A7.12)$$

This suggests there are times when the network flows create additional capacity for battery actions (e.g. network imports at times the battery is exporting), but also that the converse situation occurs, i.e. battery is exacerbating overall network flows.

At Stranraer,

$$curtailment\ costs_{battery\ and\ wind\ generator\ alone\ \ accesses\ L1} > curtailment\ cost_{town\ demand,\ \ as\ well\ as\ battery\ and\ wind\ generation,\ \ access\ L1} \qquad (A7.13)$$

though the cost difference is not great.

The battery shares the bus with the wind generator (Chapter 7 Fig 94) Thus, at times of wind generation, the battery has less access to network for its exports when a T1 malfunction isolates the bus from demand flows, than at times when T1 is working, and demand flows reduce overall network generation flows. This explains the higher curtailment cost when T1 is not working. However, the difference in curtailment costs from those of other types of network failure is not great. As displayed in Chapter 6, and discussed in later sections of Chapter 7, at Stranraer, there are also times of import dominated network flows, particularly during summer, when wind output was generally low. During such times of demand-dominated network flows, a T1 fault would reduce the import constraints on the battery. Thus, the cost difference between a T1 fault and other types of network fault at Stranraer are relatively small.

Figure 203 shows the "year average" costs of curtailment at the three locations (Armadale, Stranraer and Stevenston), for 2-hour and 4-hour batteries.

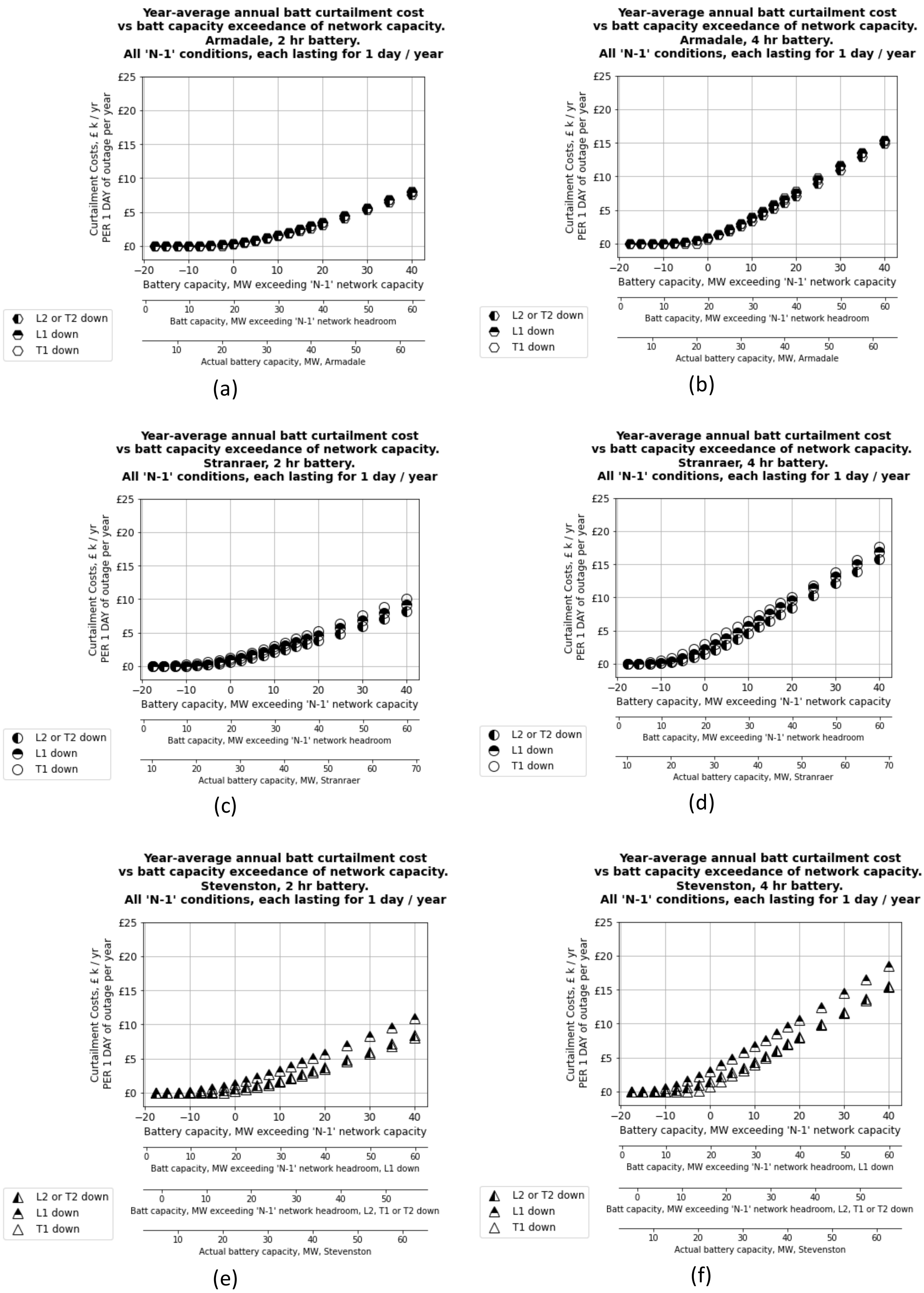


Figure 203 Year-average cost of 1 day of curtailment under 3 different "N-1" conditions, vs battery capacity. (a) Armadale, 2-hr battery; (b) Armadale, 4-hr battery; (c) Stranraer, 2-hr battery; (d) Stranraer, 4 hr battery; (e) Stevenston, 2-hr battery; (f) Stevenston, 4-hr battery.

Chapter 7 Annex 5

Abnormal operating conditions. Effect of failure rate and battery size on battery curtailment costs.

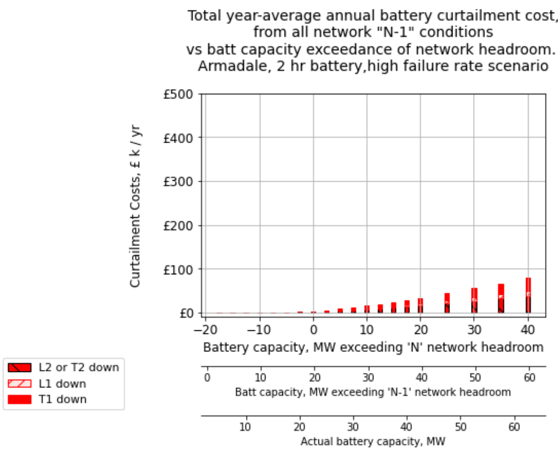
Figure 204 below shows the variation of average annual curtailment cost arising from all scenarios of 'N-1' conditions considered in this study. The contributions of the three different network conditions are shown. The charts below are for the HIGH failure scenario.

For each failure scenario, it is assumed that the rate of transformer failure would be the same for all three locations.

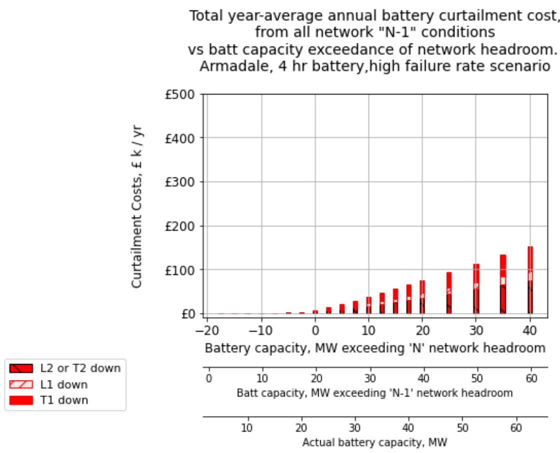
At Stevenston, curtailment costs arising from transformer failure and feeder failure are similar. Armadale, having the shortest feeders, has the lowest overall curtailment costs, with feeder failure making a smaller contribution than transformer failure. In contrast, Stranraer has long feeders, thus the highest projected rate of failure on each feeder (as failure rates are stated per km of line). Thus Stranraer's projected 'N-1' curtailment costs are the highest.

Figure 205 shows the projected overall average cost of curtailment (£ / year) vs battery capacity, for high, medium and low failure rate scenarios, at all locations, for 2-hour and 4-hour batteries.

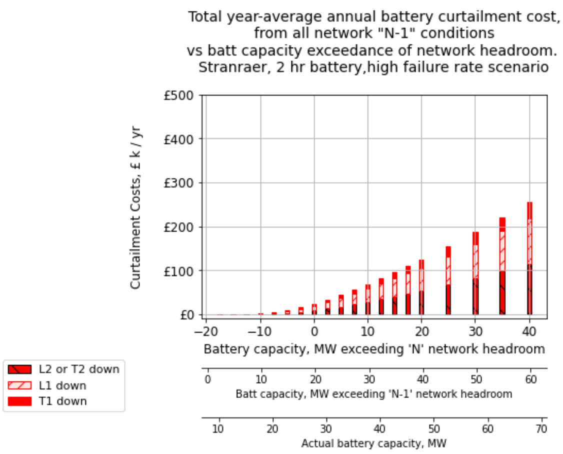
Figure 206 shows projected curtailment costs, as a proportion of overall year-average revenue a battery could accrue if not curtailed.



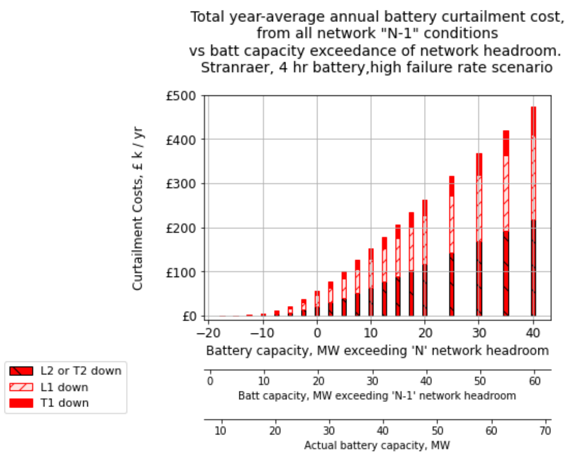
(a) Armadale, 2-hour battery



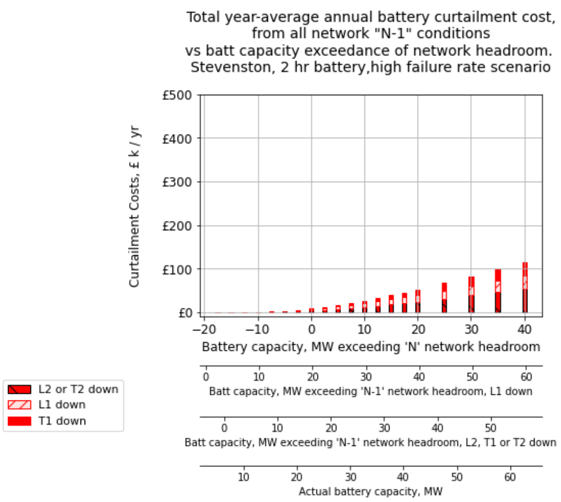
(b) Armadale, 4-hour battery



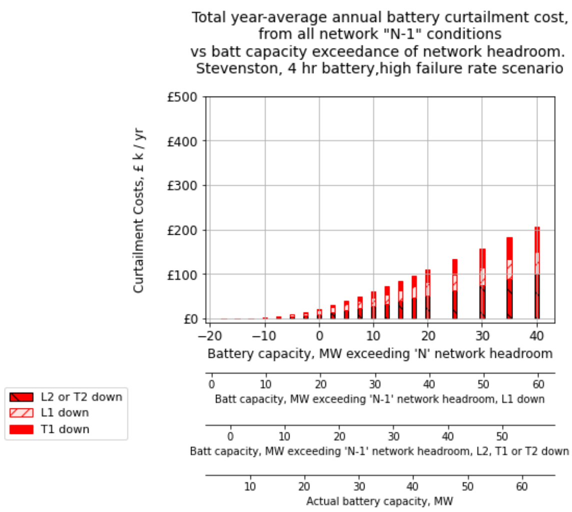
(c) Stranraer, 2-hour battery



(d) Stranraer, 4-hour battery

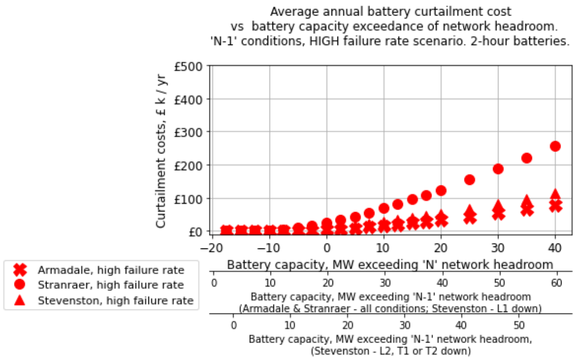


(e) Stevenston, 2-hour battery

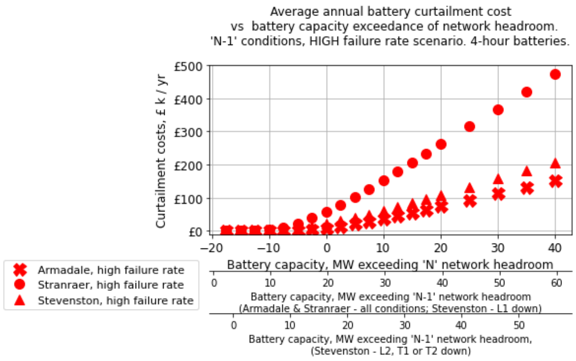


(f) Stevenston, -4hour battery

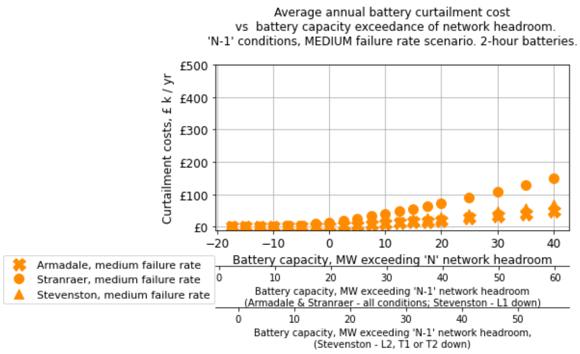
Figure 204 Variation of average annual cost of battery curtailment - arising from 'N-1' conditions - with battery MW capacity. High failure rate scenario. Showing cost contributions from the different 'N-1' conditions.



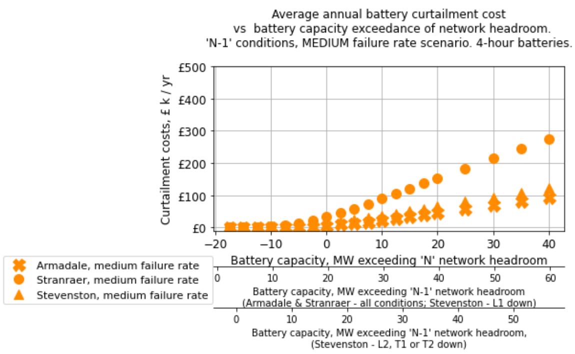
(a) High failure rate scenario, 2-hour batteries



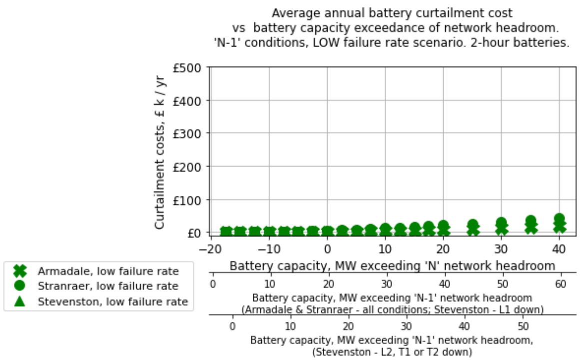
(b) High failure rate scenario, 4-hour batteries



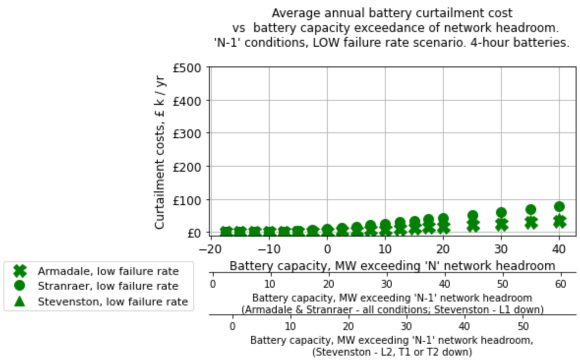
(c) Medium failure rate scenario, 2-hr batteries



(d) Medium failure rate scenario, 4-hr batteries

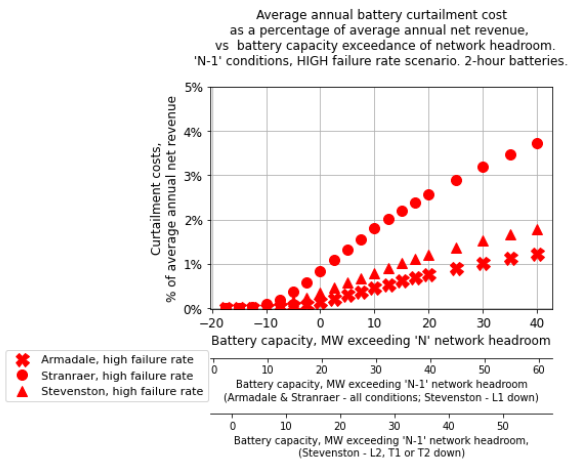


(e) Low failure rate scenario, 2-hr batteries

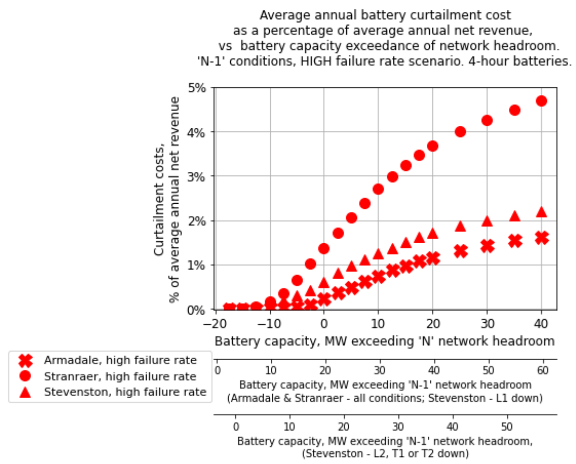


(f) Low failure rate scenario, 4-hr batteries

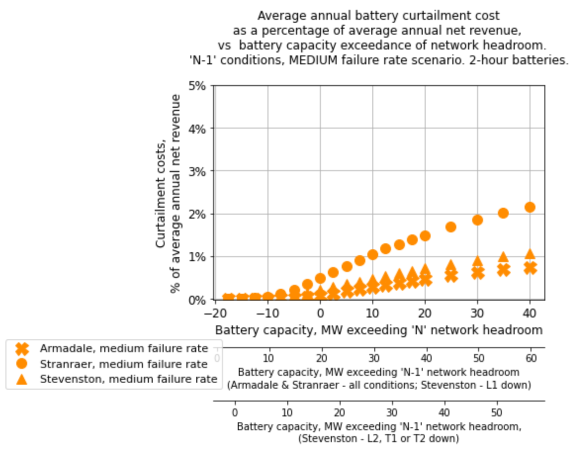
Figure 205 Variation of average annual battery curtailment cost (£/year) with battery capacity, encompassing all 'N-1' scenarios considered. Armadale, Stranraer and Stevenston; high, medium and low failure rate scenarios.



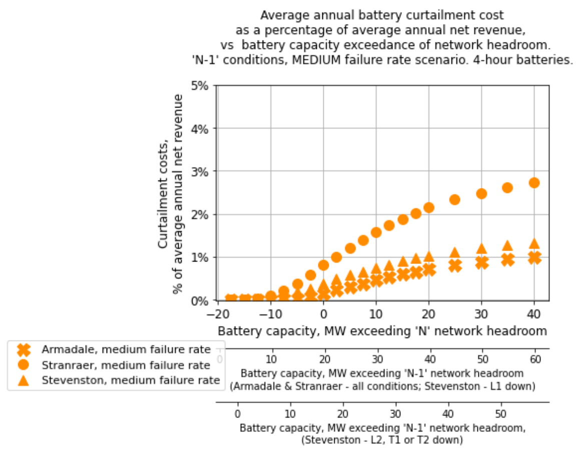
(a) High failure rate scenario, 2-hour batteries



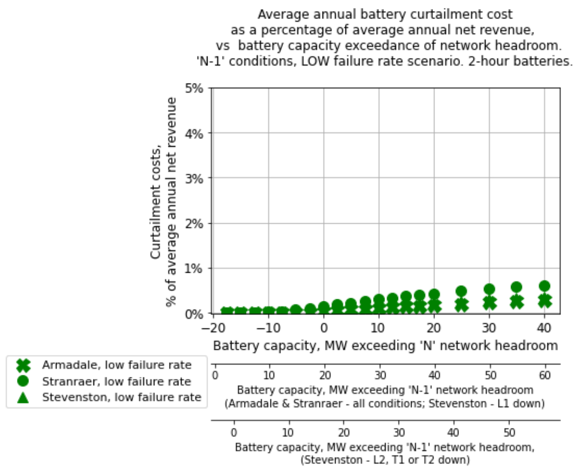
(b) High failure rate scenario, 4-hour batteries



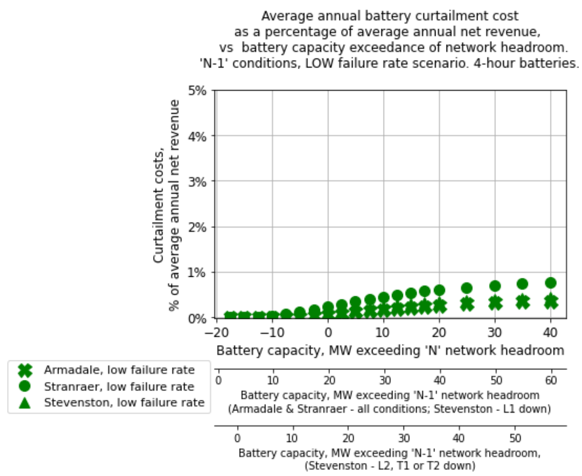
(c) Medium failure rate scenario, 2-hr batteries



(d) Medium failure rate scenario, 4-hr batteries



(e) Low failure rate scenario, 2-hr batteries



(f) Low failure rate scenario, 4-hr batteries

Figure 206 Variation of average annual battery curtailment cost, with battery capacity, encompassing all 'N-1' scenarios considered. Costs as a PROPORTION of average annual overall net revenue of an un-curtailed battery. Armadale, Stranraer and Stevenston; high, medium and low failure rate scenarios.

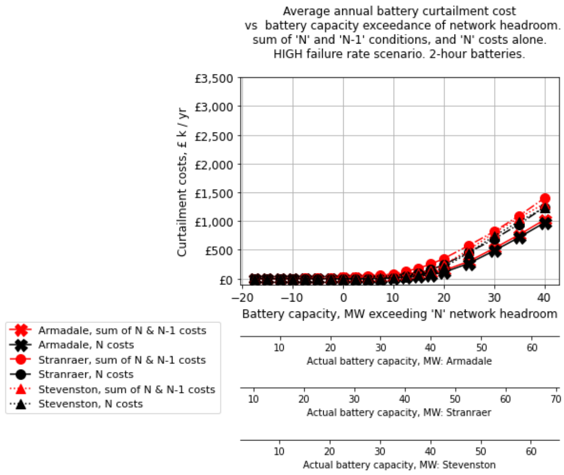
Chapter 7 Annex 6

Average annual curtailment costs, considering both ‘N’ and ‘N-1’ conditions. Armadale, Stranraer and Stevenston

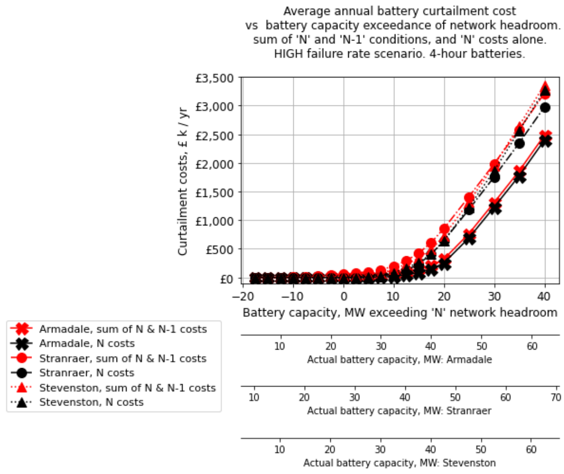
Figure 207 shows the variation of annual average curtailment costs with battery size, for both ‘N’ conditions alone, and the total of ‘N’ and ‘N-1’ curtailment costs. Costs for Armadale, Stranraer and Stevenston are potted, with separate plots for the three failure rates scenarios.

Figure 208 is a similar plot, but only showing batteries oversized by up to 20 MW above ‘N’ network headroom.

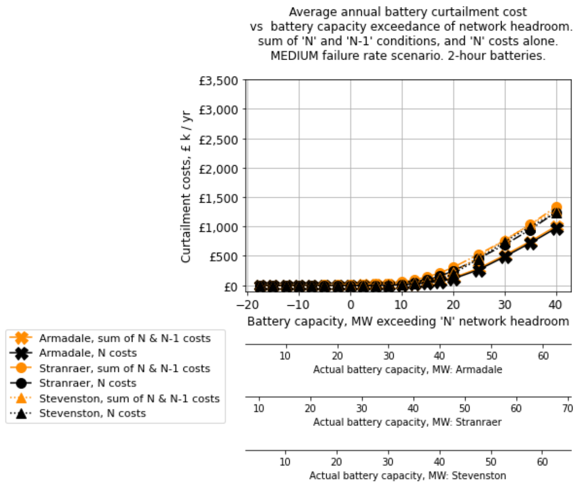
In all plots, the average annual ‘N’ costs are slightly reduced from base case costs (i.e. considering ‘N’ conditions only) displayed in Annex 3 Figure 199, to reflect that ‘N’ conditions would not apply on the number of days that ‘N-1’ conditions occur. This is up to 1-3 weeks / year, depending on failure rate scenario.



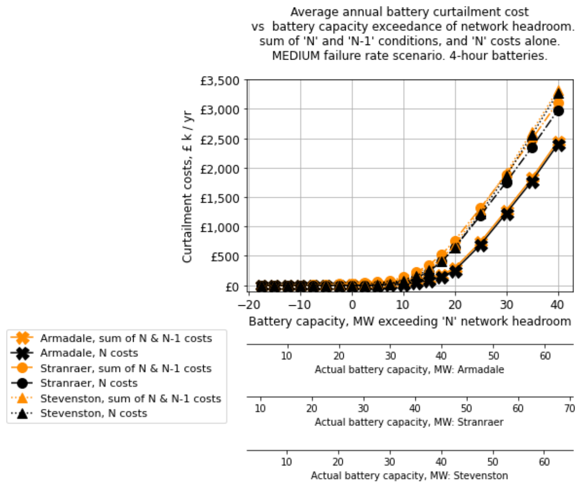
(a) High failure rate scenario, 2-hour batteries



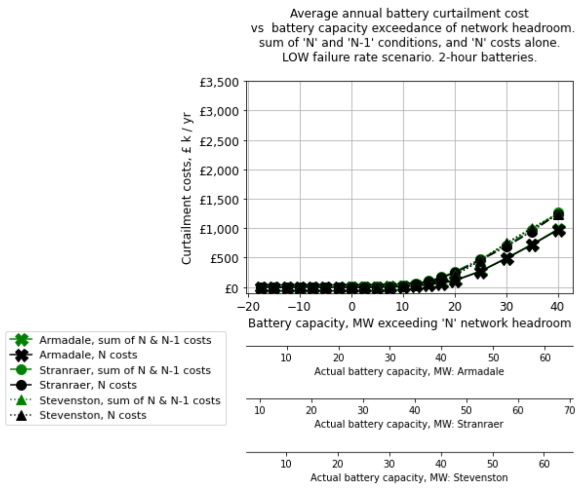
(b) High failure rate scenario, 4-hour batteries



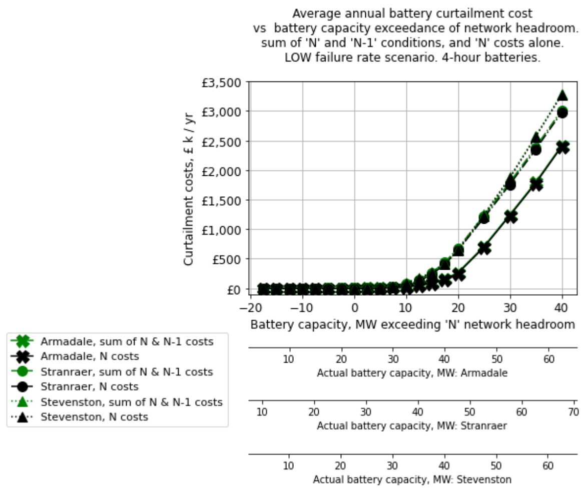
(c) Medium failure rate scenario, 2-hr batteries



(d) Medium failure rate scenario, 4-hr batteries

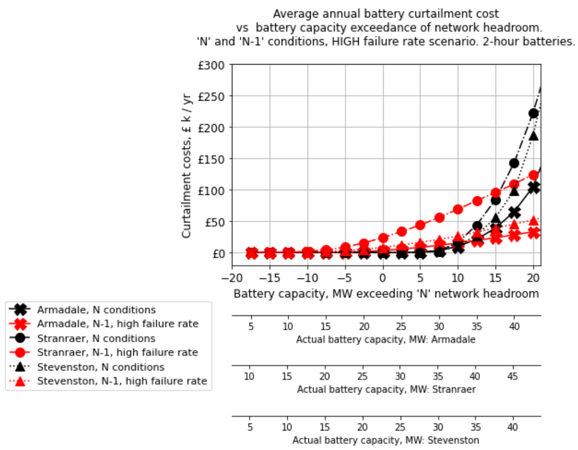


(e) Low failure rate scenario, 2-hr batteries

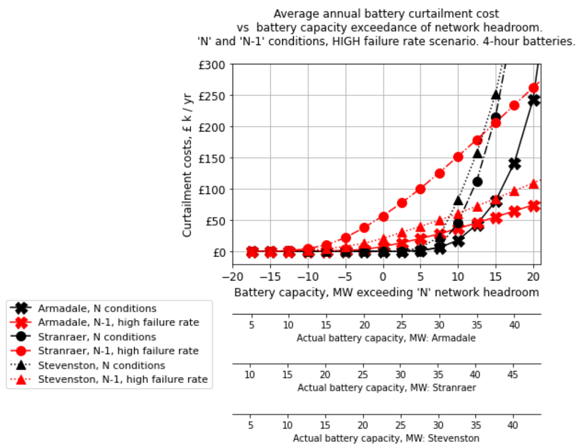


(f) Low failure rate scenario, 4-hr batteries

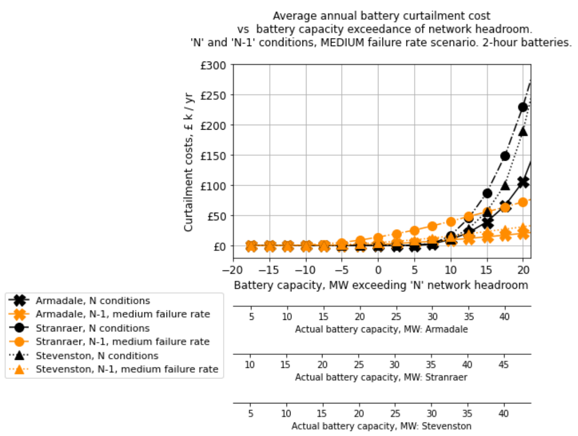
Figure 207 Average annual curtailment costs, for both 'N', and the sum of both 'N' and 'N-1' conditions. Armadale, Stranraer and Stevenston. High, medium and low failure rate scenarios, full range of battery sizes.



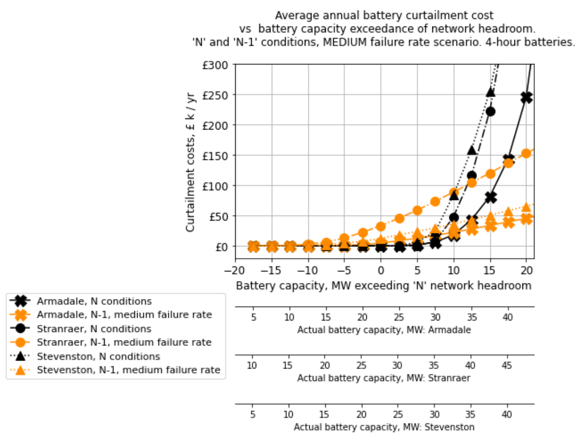
(a) High failure rate scenario, 2-hr batteries



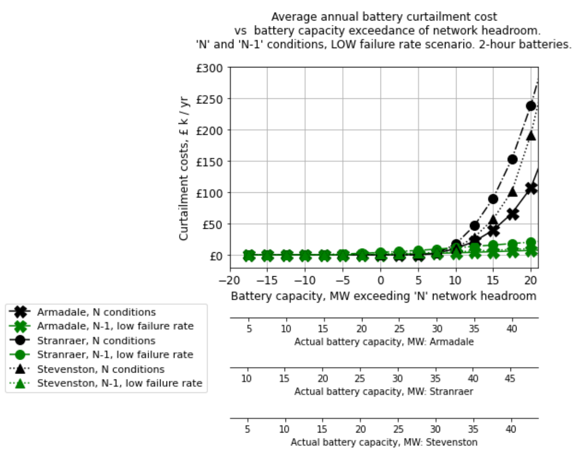
(b) High failure rate scenario, 4-hr batteries



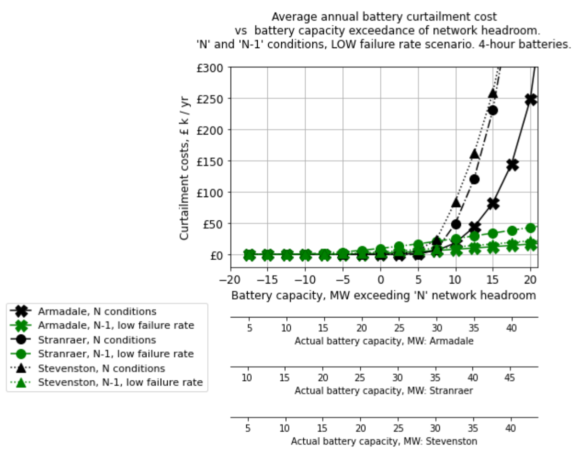
(c) Medium failure rate scenario, 2-hr batteries



(d) Medium failure rate scenario, 4-hr batteries



(e) Low failure rate scenario, 2-hr batteries



(f) Low failure rate scenario, 4-hr batteries

Figure 208 Average annual curtailment costs, considering both 'N' and 'N-1' conditions. Battery capacities up to 20 MW above 'N' network headroom. Armadale, Stranraer and Stevenston. High, medium and low failure rate scenarios.

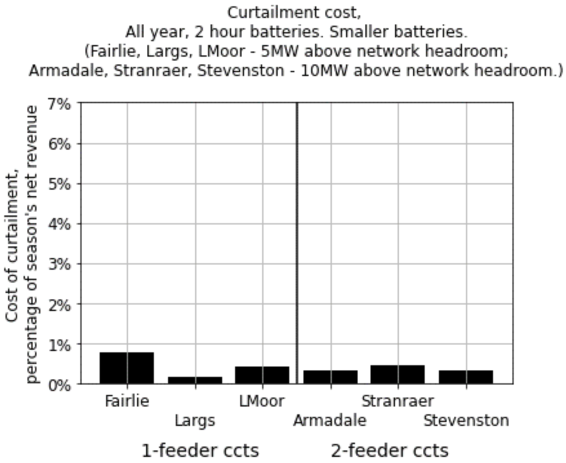
Chapter 7 Annex 7

Battery trades analysis

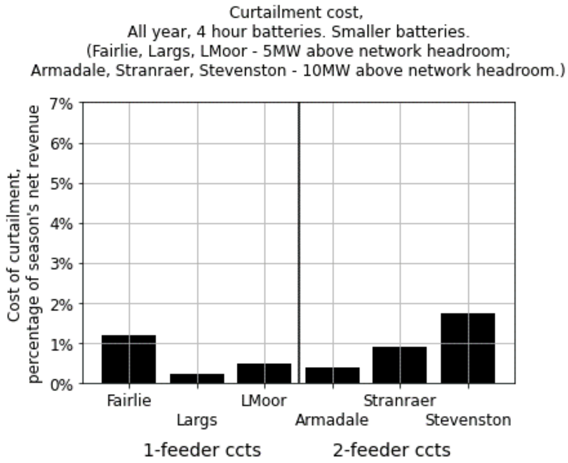
"Smaller" and "larger" battery sizes were selected for analysis of trades, in both cases, aiming for a size (MW capacity) of battery which exceeded network headroom, but at which curtailment costs were very low.

- "Smaller batteries"
  - Fairlie, Largs, Lochan Moor – 5 MW above network headroom
  - Armadale, Stranraer, Stevenston – 10 MW above network headroom
- "Larger batteries"
  - Fairlie, Largs, Lochan Moor – 7.5 MW above network headroom
  - Armadale, Stranraer, Stevenston – 15 MW above network headroom

Figure 209 and Figure 210 show the *proportional* average annual curtailment costs of a battery (i.e. costs compared with overall net revenue on an unconstrained network), at all case study locations, for "smaller" and "larger" batteries, respectively.

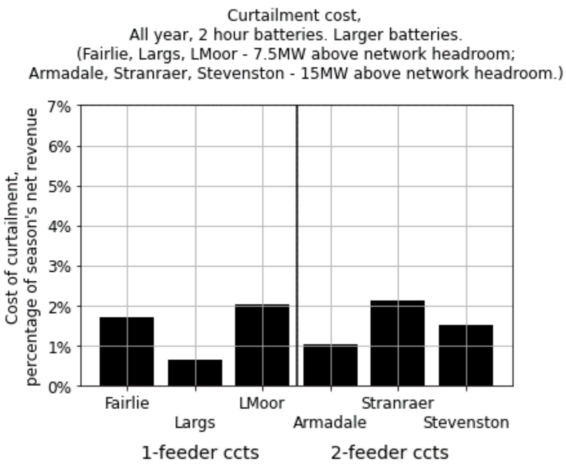


(a) 2-hour batteries

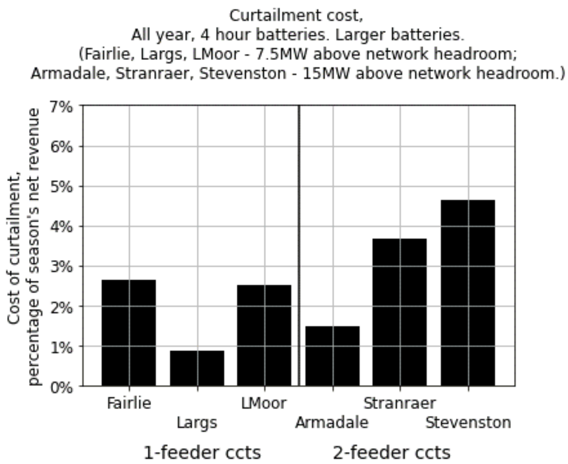


(b) 4-hour batteries

Figure 209 Average annual curtailment costs, all locations, "SMALLER" batteries: 5 MW over network headroom (Fairlie, Largs, Lochan Moor); 10 MW over network headroom (Armadale, Stranraer, Stevenston. (a) 2-hour batteries; (b) 4-hour batteries.



(a) 2-hour batteries

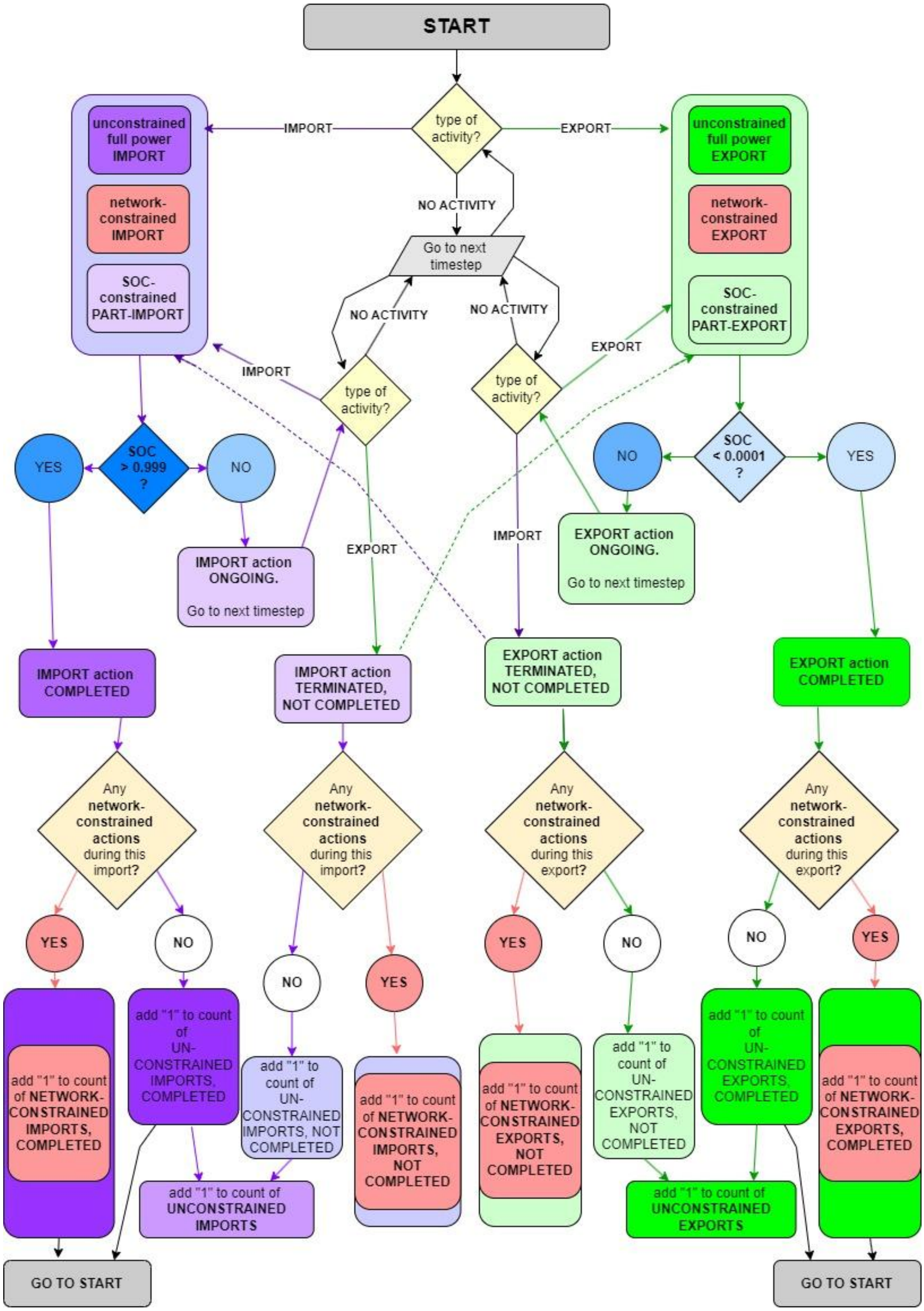


(b) 4-hour batteries

Figure 210 Average annual curtailment costs, all locations, "LARGER" batteries: 7.5 MW over network headroom (Fairlie, Largs, Lochan Moor); 15 MW over network headroom (Armadale, Stranraer, Stevenston. (a) 2-hour batteries; (b) 4-hour batteries.

Chapter 7 Annex 8

Battery trades analysis. Flowchart of logic



Chapter 7 Annex 9

Battery categorisation results: trades affected / not affected by network constraints; trades completed / not completed.

The tables below show the numbers of battery trades split into categories (as per the logic shown in the previous Annex): trades completed / not completed; trades unconstrained / constrained by network limits. Each table is for one case study season, all locations, 2-hour and 4-hour batteries, and either "smaller" batteries (Table 125, Table 126 and Table 127), or for "larger" batteries (Table 128, Table 129 and Table 130). Battery sizes chosen for low curtailment costs. All are under "N" network conditions.

Table 125 Battery trade categorisation: numbers of trades in every category. **Autumn**. ***"Smaller" batteries*:** 5 MW > network headroom (Fairlie, Largs, Lochan Moor) / 10 MW above network headroom (Armadale, Stranraer, Stevenston) 2-hour and 4-hour batteries.

Location	**Type of trade**	**2-hour batteries**						**4-hour batteries**					
		Imports			**Exports**			**Imports**			**Exports**		
		Completed	Not completed	All	Complet'd	Not complet'd	All	Completed	Not completed	All	Completed	Not completed	All
Fairlie	Unconstrained	65	10	75	59	4	63	46	25	71	35	22	57
	Network-constrained	0	0	0	11	2	13	0	0	0	9	6	15
	All	65	10	75	70	6	76	46	25	71	44	28	72
Largs	Unconstrained	65	10	75	68	4	72	54	14	68	39	25	64
	Network-constrained	0	0	0	4	0	4	0	0	0	1	4	5
	All	65	10	75	72	4	76	54	14	68	40	29	69
Lochan Moor	Unconstrained	65	10	75	67	3	70	54	14	68	38	25	63
	Network-constrained	0	0	0	5	1	6	0	0	0	1	5	6
	All	65	10	75	72	4	76	54	14	68	39	30	69
Armadale	Unconstrained	65	10	75	61	4	65	54	14	68	31	25	56
	Network-constrained	0	0	0	11	0	11	0	0	0	7	6	13
	All	65	10	75	72	4	76	54	14	68	38	31	69
Stranraer	Unconstrained	39	6	45	43	2	45	31	9	40	25	11	36
	Network-constrained	26	4	30	25	6	31	23	5	28	8	25	33
	All	65	10	75	68	8	76	54	14	68	33	36	69
Steven-ston	Unconstrained	0	0	0	72	4	76	0	0	0	44	25	69
	Network-constrained	64	11	75	0	0	0	47	21	68	0	0	0
	All	64	11	75	72	4	76	47	21	68	44	25	69

Table 126 Battery trade categorisation: numbers of trades completed and not completed, and unconstrained / network-constrained trades. **Winter.** ***"Smaller" batteries***: 5 MW > network headroom (Fairlie, Largs, Lochan Moor) / 10 MW above network headroom (Armadale, Stranraer, Stevenston) **2-hour & 4 hour batteries**.

Location	**Type of trade**	**2-hour batteries**						**4-hour batteries**					
		Imports			**Exports**			**Imports**			**Exports**		
		Completed	Not completed	All	Complet'd	Not complet'd	All	Completed	Not completed	All	Completed	Not completed	All
Fairlie	Unconstrained	37	4	41	35	1	36	34	2	36	26	4	30
	Network-constrained	0	0	0	6	0	6	0	0	0	4	2	6
	All	37	4	41	41	1	42	34	2	36	30	6	36
Largs	Unconstrained	37	4	41	41	1	42	34	2	36	30	5	35
	Network-constrained	0	0	0	0	0	0	0	0	0	1	0	1
	All	37	4	41	41	1	42	34	2	36	31	5	36
Lochan Moor	Unconstrained	37	4	41	41	1	42	34	2	36	31	5	36
	Network-constrained	0	0	0	0	0	0	0	0	0	0	0	0
	All	37	4	41	41	1	42	34	2	36	31	5	36
Armadale	Unconstrained	37	4	41	41	1	42	34	2	36	31	5	36
	Network-constrained	0	0	0	0	0	0	0	0	0	0	0	0
	All	37	4	41	41	1	42	34	2	36	31	5	36
Stranraer	Unconstrained	37	4	41	39	1	40	34	2	36	30	5	35
	Network-constrained	0	0	0	1	1	2	0	0	0	1	0	1
	All	37	4	41	40	2	42	34	2	36	31	5	36
Steven-ston	Unconstrained	0	0	0	41	1	42	0	0	0	31	5	36
	Network-constrained	37	4	41	0	0	0	33	3	36	0	0	0
	All	37	4	41	41	1	42	33	3	36	31	5	36

Table 127 Battery trade categorisation: numbers of trades in every category. **Summer**. ***"Smaller" batteries***: 5 MW > network headroom (Fairlie, Largs, Lochan Moor) / 10 MW above network headroom (Armadale, Stranraer, Stevenston) **2-hour and 4-hour batteries**.

Location	Type of trade	2-hour batteries						4-hour batteries					
		Imports			Exports			Imports			Exports		
		Completed	Not completed	All	Complet'd	Not complet'd	All	Completed	Not completed	All	Completed	Not completed	All
Fairlie	Unconstrained	56	9	65	57	4	61	47	16	63	40	20	60
	Network-constrained	0	0	0	3	1	4	0	0	0	2	1	3
	All	56	9	65	60	5	65	47	16	63	42	21	63
Largs	Unconstrained	56	9	65	58	5	63	47	16	63	40	20	60
	Network-constrained	0	0	0	1	1	2	0	0	0	1	2	3
	All	56	9	65	59	6	65	47	16	63	41	22	63
Lochan Moor	Unconstrained	56	9	65	50	4	54	48	15	63	33	19	52
	Network-constrained	0	0	0	5	6	11	0	0	0	4	7	11
	All	56	9	65	55	10	65	48	15	63	37	26	63
Armadale	Unconstrained	56	9	65	54	4	58	47	16	63	37	19	56
	Network-constrained	0	0	0	5	2	7	0	0	0	4	3	7
	All	56	9	65	59	6	65	47	16	63	41	22	63
Stranraer	Unconstrained	20	4	24	54	4	58	13	7	20	37	20	57
	Network-constrained	36	5	41	6	1	7	32	11	43	4	2	6
	All	56	9	65	60	5	65	45	18	63	41	22	63
Steven-ston	Unconstrained	0	0	0	60	5	65	0	0	0	42	21	63
	Network-constrained	56	9	65	0	0	0	36	27	63	0	0	0
	All	56	9	65	60	5	65	36	27	63	42	21	63

Table 128 Battery trade categorisation: numbers of trades in every category. **Autumn**. ***"Larger" batteries***: 7.5 MW > network headroom (Fairlie, Largs, Lochan Moor) / 15 MW above network headroom (Armadale, Stranraer, Stevenston) 2-hour and 4-hour batteries.

Location	**Type of trade**	**2-hour batteries**						**4-hour batteries**					
		Imports			**Exports**			**Imports**			**Exports**		
		Completed	Not completed	All	Complet'd	Not complet'd	All	Completed	Not completed	All	Completed	Not completed	All
Fairlie	Unconstrained	66	9	75	51	4	55	46	25	71	30	19	49
	Network-constrained	0	0	0	17	4	21	0	0	0	9	14	23
	All	66	9	75	68	8	76	46	25	71	39	33	72
Largs	Unconstrained	65	10	75	53	4	57	54	14	68	32	19	51
	Network-constrained	0	0	0	16	3	19	0	0	0	6	12	18
	All	65	10	75	69	7	76	54	14	68	38	31	69
Lochan Moor	Unconstrained	66	9	75	51	2	53	47	24	71	31	17	48
	Network-constrained	0	0	0	18	5	23	0	0	0	9	15	24
	All	66	9	75	69	7	76	47	24	71	40	32	72
Armadale	Unconstrained	38	6	44	52	3	55	31	8	39	28	19	47
	Network-constrained	27	4	31	17	4	21	23	6	29	8	14	22
	All	65	10	75	69	7	76	54	14	68	36	33	69
Stranraer	Unconstrained	9	1	10	14	0	14	7	2	9	7	2	9
	Network-constrained	57	8	65	49	13	62	45	14	59	22	38	60
	All	66	9	75	63	13	76	52	16	68	29	40	69
Steven-ston	Unconstrained	0	0	0	72	4	76	0	0	0	45	24	69
	Network-constrained	55	20	75	0	0	0	36	32	68	0	0	0
	All	55	20	75	72	4	76	36	32	68	45	24	69

Table 129 Battery trade categorisation: numbers of trades in every category. **Winter.** ***"Larger" batteries***: 7.5 MW > network headroom (Fairlie, Largs, Lochan Moor) / 15 MW above network headroom (Armadale, Stranraer, Stevenston) 2-hour and 4-hour batteries.

Location	Type of trade	2-hour batteries						4-hour batteries					
		Imports			Exports			Imports			Exports		
		Completed	Not completed	All	Complet'd	Not complet'd	All	Completed	Not completed	All	Completed	Not completed	All
Fairlie	Unconstrained	37	4	41	32	1	33	34	2	36	24	2	26
	Network-constrained	0	0	0	8	1	9	0	0	0	5	5	10
	All	37	4	41	40	2	42	34	2	36	29	7	36
Largs	Unconstrained	37	4	41	39	1	40	34	2	36	29	5	34
	Network-constrained	0	0	0	2	0	2	0	0	0	2	0	2
	All	37	4	41	41	1	42	34	2	36	31	5	36
Lochan Moor	Unconstrained	37	4	41	31	1	32	34	2	36	24	3	27
	Network-constrained	0	0	0	9	1	10	0	0	0	4	5	9
	All	37	4	41	40	2	42	34	2	36	28	8	36
Armadale	Unconstrained	26	4	30	36	1	37	19	1	20	25	4	29
	Network-constrained	11	0	11	5	0	5	15	1	16	4	3	7
	All	37	4	41	41	1	42	34	2	36	29	7	36
Stranraer	Unconstrained	37	4	41	37	1	38	33	2	35	27	5	32
	Network-constrained	0	0	0	3	1	4	1	0	1	3	1	4
	All	37	4	41	40	2	42	34	2	36	30	6	36
Steven-ston	Unconstrained	0	0	0	41	1	42	0	0	0	32	4	36
	Network-constrained	36	5	41	0	0	0	32	4	36	0	0	0
	All	36	5	41	41	1	42	32	4	36	32	4	36

Table 130 Battery trade categorisation: numbers of trades in every category. **Summer.** ***"Larger" batteries***: 7.5 MW > network headroom (Fairlie, Largs, Lochan Moor) / 15 MW above network headroom (Armadale, Stranraer, Stevenston) 2-hour and 4-hour batteries.

Location	**Type of trade**	**2-hour batteries**						**4-hour batteries**					
		Imports			**Exports**			**Imports**			**Exports**		
		Completed	Not completed	All	Complet'd	Not complet'd	All	Completed	Not completed	All	Completed	Not completed	All
Fairlie	Unconstrained	56	9	65	51	3	54	47	16	63	35	19	54
	Network-constrained	0	0	0	8	3	11	0	0	0	5	4	9
	All	56	9	65	59	6	65	47	16	63	40	23	63
Largs	Unconstrained	56	9	65	55	4	59	47	16	63	39	19	58
	Network-constrained	0	0	0	4	2	6	0	0	0	2	3	5
	All	56	9	65	59	6	65	47	16	63	41	22	63
Lochan Moor	Unconstrained	56	9	65	46	3	49	48	15	63	32	18	50
	Network-constrained	0	0	0	8	8	16	0	0	0	2	11	13
	All	56	9	65	54	11	65	48	15	63	34	29	63
Armadale	Unconstrained	28	7	35	48	3	51	19	13	32	30	19	49
	Network-constrained	28	2	30	11	3	14	26	5	31	10	4	14
	All	56	9	65	59	6	65	45	18	63	40	23	63
Stranraer	Unconstrained	3	2	5	21	0	21	1	2	3	13	4	17
	Network-constrained	53	7	60	34	10	44	35	25	60	21	25	46
	All	56	9	65	55	10	65	36	27	63	34	29	63
Steven-ston	Unconstrained	0	0	0	60	5	65	0	0	0	37	17	54
	Network-constrained	53	12	65	0	0	0	24	30	54	0	0	0
	All	53	12	65	60	5	65	24	30	54	37	17	54

Chapter 7 Annex 10

Categorisation of battery trades, and seasons' curtailment costs

Battery trades, both imports and exports, are categorised as "unconstrained [by network capacity]"; "network-constrained – completed"; "network -constrained – not completed" .

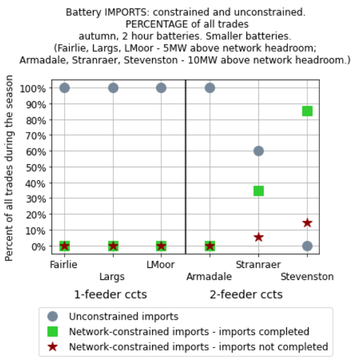
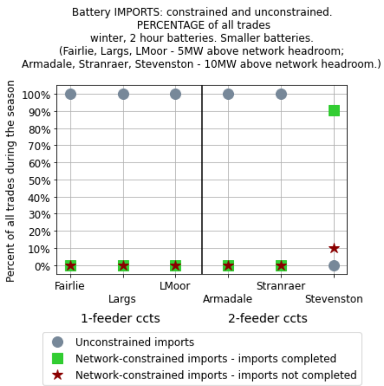
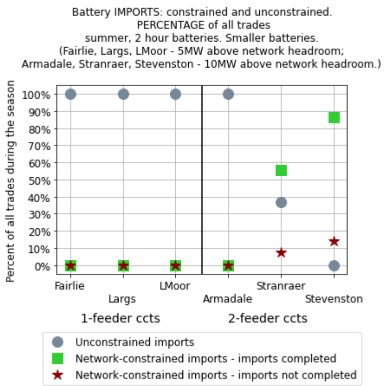
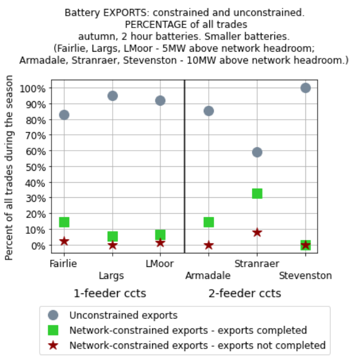
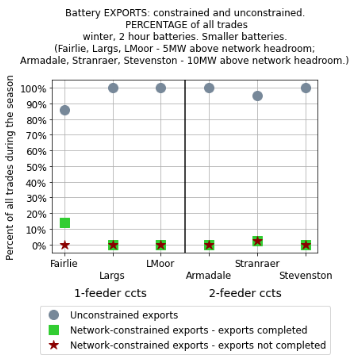
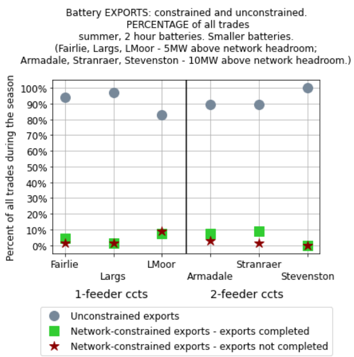
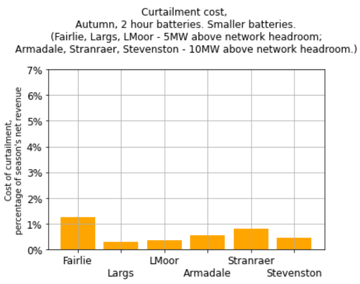
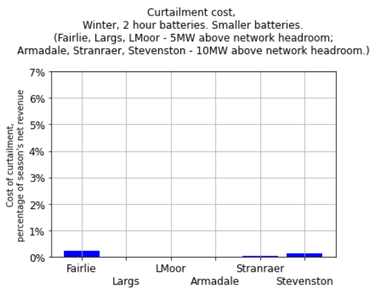
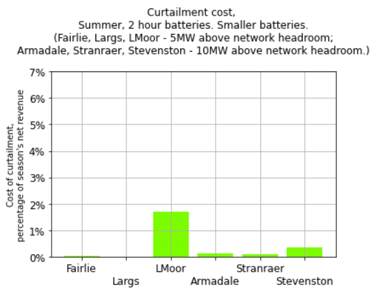
	Autumn	**Winter**	**Summer**
Im-ports			
Ex-ports			
Curt Cost *			

Figure 211 Categorisation of battery trades, and curtailment costs. 2-hour batteries, "smaller" batteries, all seasons

*Curtailment costs, as a percentage of the season's net overall revenue, without constraints

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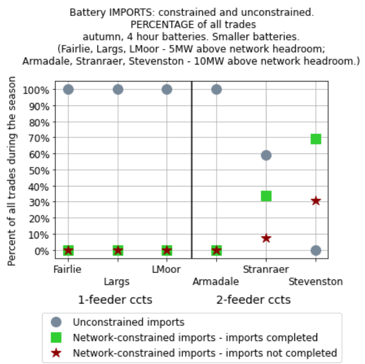
<td>
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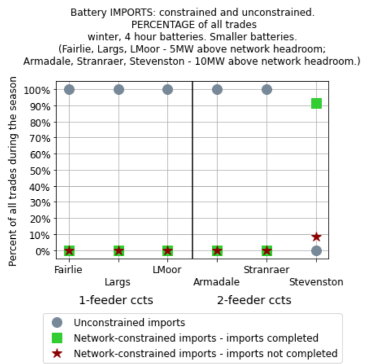
<td>
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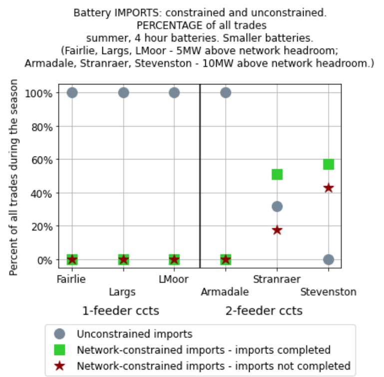
<td>
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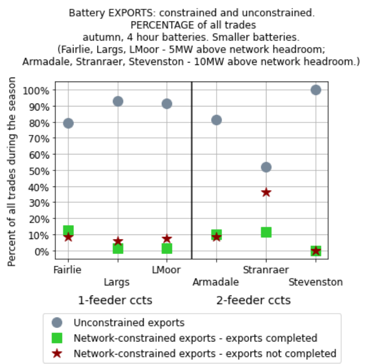
<td>
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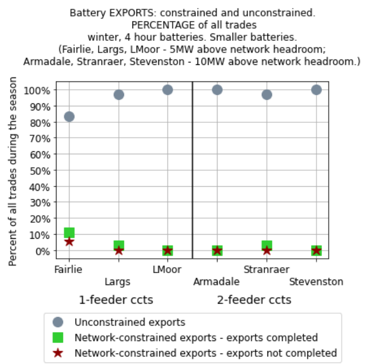
<td>
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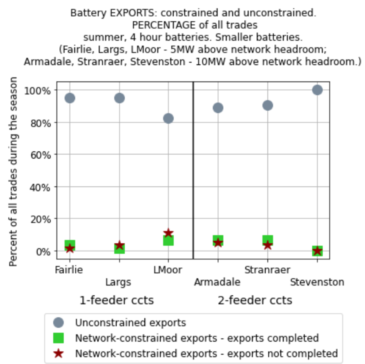
<td>
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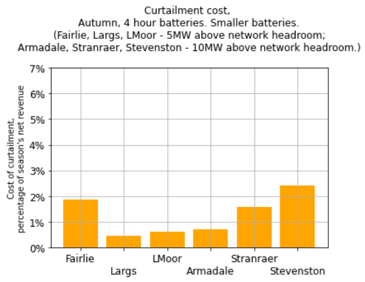
<tr><td>Curt costs *</td>
<td>
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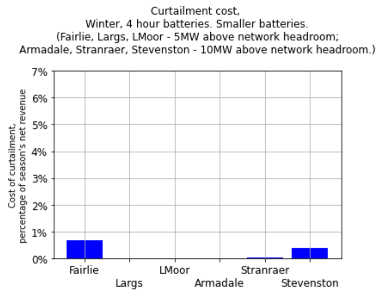
<td>
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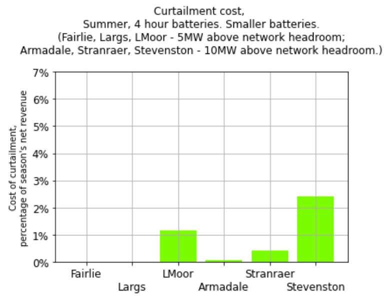
<td>
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</table>

Figure 212 Categorisation of battery trades, and curtailment costs. 4-hour batteries, “smaller” batteries, all seasons

*Curtailment costs, as a percentage of the season’s net overall revenue, without constraints

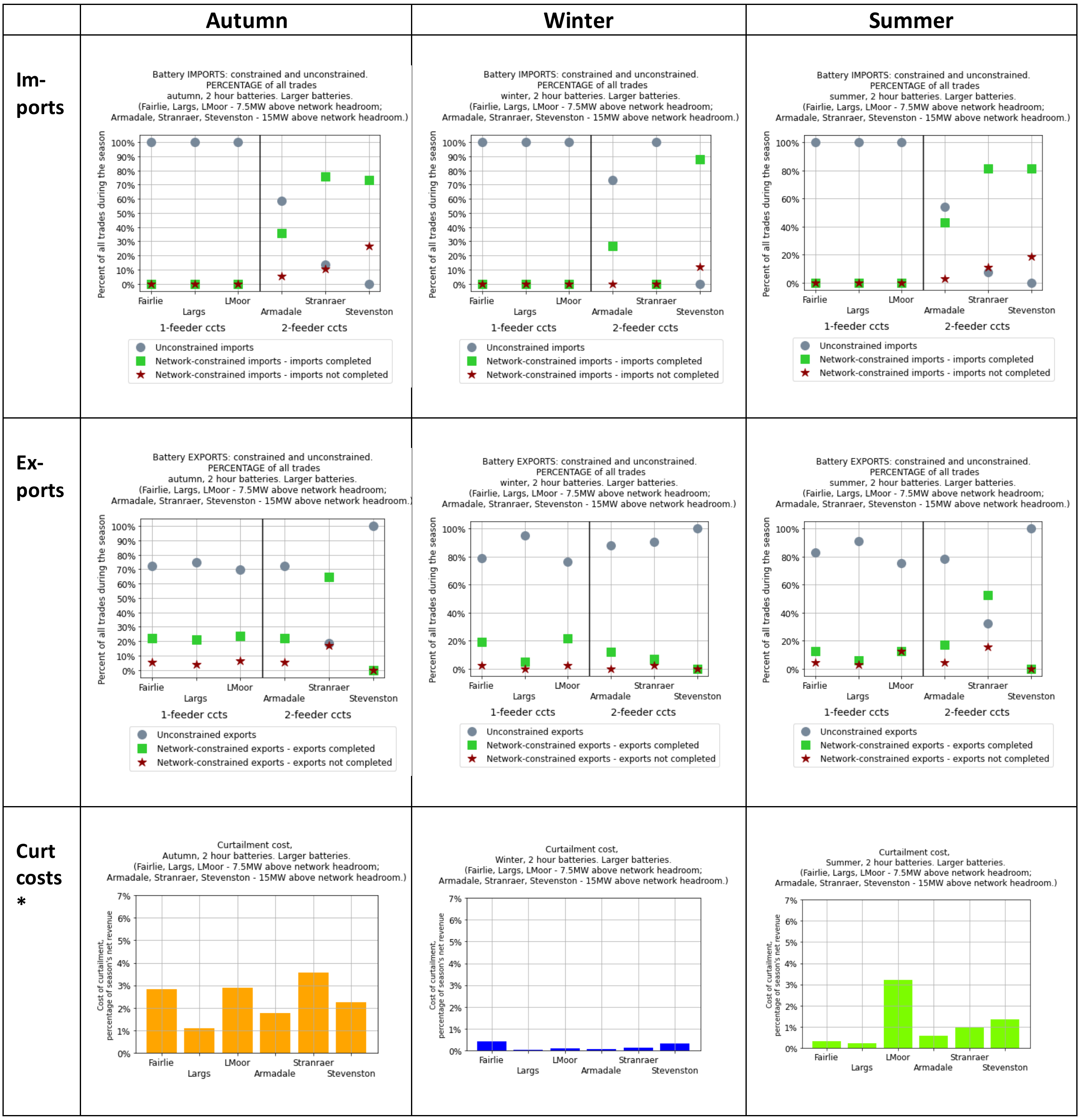

Figure 213 Categorisation of battery trades, and curtailment costs. 2-hour batteries, “larger” batteries, all seasons

*Curtailment costs, as a percentage of the season’s net overall revenue, without constraints

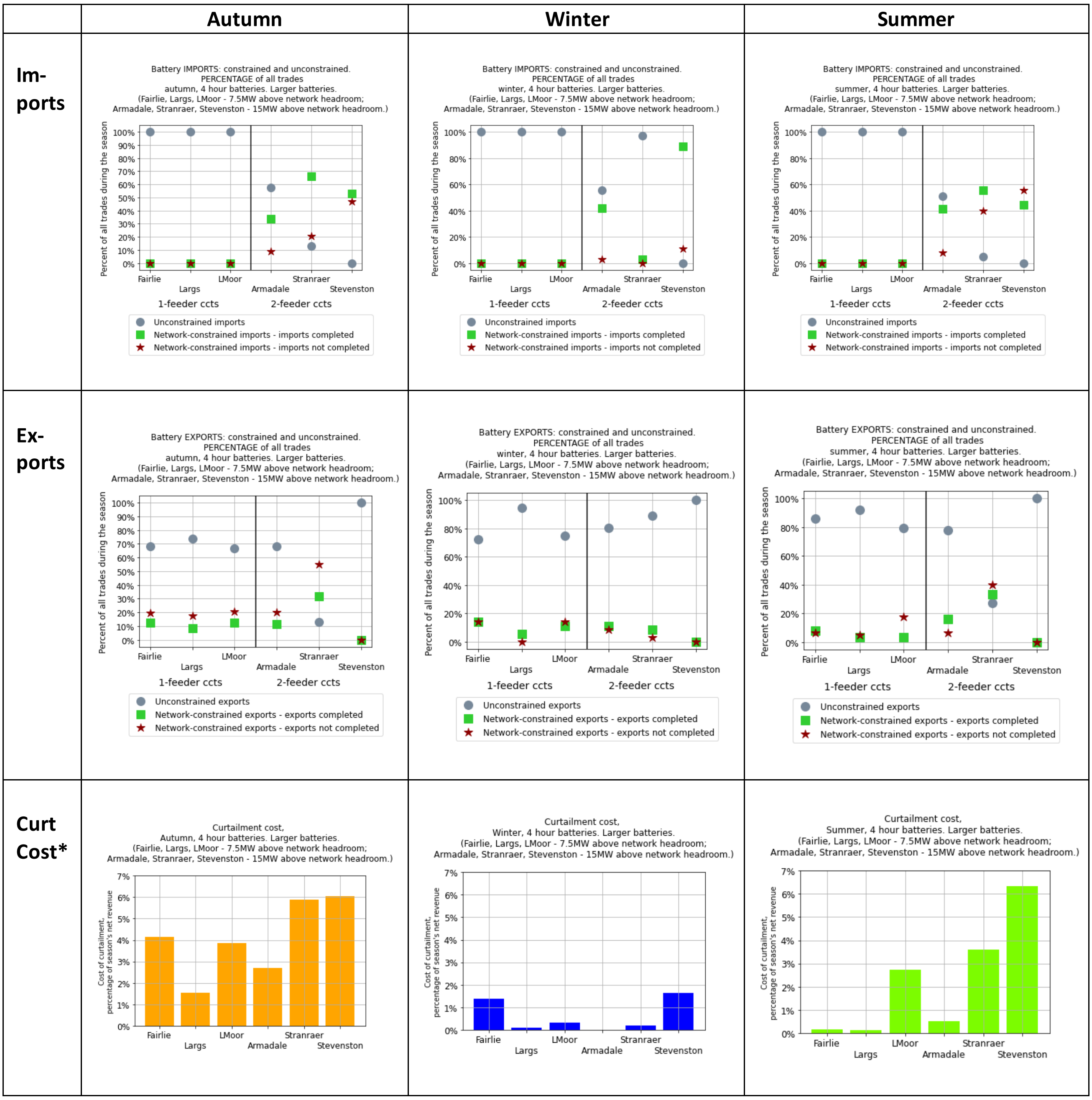

Figure 214 Categorisation of battery trades. 4-hour batteries, “larger” batteries, all seasons

*Curtailment costs, as a percentage of the season’s net overall revenue, without constraints

Annexes to Chapter 8
Comparison of battery curtailment with network reinforcement on costs and other factors

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Chapter 8 Annex 1

Annual curtailment costs – no network reinforcement

Table 131 Projected annual battery curtailment costs, no network reinforcement, for Fairlie, Largs and Lochan Moor. "N" network conditions only

Battery capacity in excess of network headroom, MW	Projected annual curtailment costs, £ (2022)					
	Location and battery duration					
	Fairlie	Largs	Lochan Moor	Fairlie	Largs	Lochan Moor
	2hr	2hr	2hr	4hr	4hr	4hr
0	0	0	-	0	0	-
2.5	1,307	231	242	2,365	662	478
5.0	9,223	1,944	2,619	21,563	4,160	4,540
7.5	24,973	9,455	16,269	57,290	18,690	29,621
10.0	51,418	26,001	45,531	109,891	49,452	85,943
12.5	95,855	49,903	88,146	204,131	102,886	170,844
15.0	172,514	90,733	144,123	384,679	209,839	277,354
17.5	281,085	158,996	213,283	658,792	394,120	404,370
20.0	400,282	245,632	293,719	963,281	619,981	550,493

Table 132 Projected annual battery curtailment costs, no network reinforcement. Armadale, Stranraer and Stevenston, including "N" and "N-1" network conditions, medium failure rate scenario

Battery capacity in excess of network headroom, MW	Projected annual curtailment costs, £ (2022)					
	Location and battery duration					
	Armadale	Stranraer	Stevenston	Armadale	Stranraer	Stevenston
	2hr	2hr	2hr	4hr	4hr	4hr
-17.5	-	4	- 0	- 0	4	- 0
-15	4	60	3	12	152	25
-12.5	26	250	66	55	698	218
-10	95	925	281	189	2,478	905
-7.5	226	2,391	818	449	6,212	2,331
-5	435	4,995	1,613	917	12,762	4,676
-2.5	814	8,862	2,817	1,856	22,254	7,493
0	1,852	13,815	4,835	4,637	33,165	12,278
2.5	3,219	19,454	7,058	8,391	45,336	18,053
5	5,561	25,381	9,825	14,425	58,842	29,759
7.5	9,666	34,869	16,241	23,010	80,478	53,209
10	19,104	56,675	26,236	40,519	136,170	119,626
12.5	33,063	93,202	47,100	71,275	221,045	202,545
15	53,420	142,911	79,527	115,029	343,155	306,052
17.5	82,903	211,995	127,259	182,813	523,915	450,806
20	125,906	302,584	220,298	291,479	762,118	687,534
25	286,022	524,919	478,588	734,704	1,315,457	1,281,102
30	508,759	761,984	771,214	1,274,258	1,886,094	1,913,999
35	744,401	1,031,471	1,031,367	1,825,516	2,484,691	2,614,126
40	1,001,571	1,331,174	1,274,206	2,446,520	3,112,600	3,322,116

Chapter 8 Annex 2

Enumeration of whole lifetime battery curtailment costs

Using annual discount rate of 8%, added annually:

Y = no. of years in the future

r = annual discount rate, added annually, taken as 8%

Table 133 Calculation of projected whole lifetime cost of battery curtailment, “one lifetime” scenario

Col A	**Column B**	**Column C**	**Column D**
Year	Battery degradation: curtailment cost multiplier	NPV of future year’s curtailment cost	NPV of whole lifetime curtailment cost
y	= (1 - 0.05*y)	= Column B.$(1+r)^y$	$\sum_{y=0}^{y=9}(column\ C)$
			5.844
0	1	1.0000	
1	0.95	0.8796	
2	0.9	0.7716	
3	0.85	0.6748	
4	0.8	0.5880	
5	0.75	0.5104	
6	0.7	0.4411	
7	0.65	0.3793	
8	0.6	0.3242	
9	0.55	0.2751	

Table 134 Calculation of projected whole lifetime cost of battery curtailment, "four lifetimes" scenario

Col A	**Column B**	**Column C**	**Column D**
Year	Battery degradation: curtailment cost multiplier	NPV of future year's curtailment cost	NPV of whole lifetime curtail. cost
y	= (1 - 0.05*y) With y reset to zero every 10 years	= Column B.$(1+r)^y$	$\sum_{y=0}^{y=39} (column\ C)$
			10.386
0	1	1.0000	
1	0.95	0.8796	
2	0.9	0.7716	
3	0.85	0.6748	
4	0.8	0.5880	
5	0.75	0.5104	
6	0.7	0.4411	
7	0.65	0.3793	
8	0.6	0.3242	
9	0.55	0.2751	
10	1	0.4632	
11	0.95	0.4074	
12	0.9	0.3574	
13	0.85	0.3125	
14	0.8	0.2724	
15	0.75	0.2364	
16	0.7	0.2043	
17	0.65	0.1757	
18	0.6	0.1501	
19	0.55	0.1274	
20	1	0.2145	
21	0.95	0.1887	
22	0.9	0.1655	
23	0.85	0.1448	
24	0.8	0.1262	
25	0.75	0.1095	
26	0.7	0.0946	
27	0.65	0.0814	
28	0.6	0.0695	
29	0.55	0.0590	
30	1	0.0994	
31	0.95	0.0874	
32	0.9	0.0767	
33	0.85	0.0671	
34	0.8	0.0584	
35	0.75	0.0507	
36	0.7	0.0438	
37	0.65	0.0377	
38	0.6	0.0322	
39	0.55	0.0273	

Chapter 8 Annex 3

Annual and projected whole lifetime battery curtailment costs, no network reinforcement

Table 135 Annual and whole project lifetime costs of battery curtailment, without network reinforcement. Fairlie, Largs, Lochan Moor, 2-hour batteries

Battery capacity in excess of network headroom, MW	Fairlie, 2hr batteries			Largs, 2hr batteries			Lochan Moor, 2hr batteries		
	Annual cost, £	NPV whole lifetime costs, £		Annual cost, £	NPV whole lifetime costs, £		Annual cost, £	NPV whole lifetime costs, £	
		1 batt lifetime	4 batt lifetimes		1 batt lifetime	4 batt lifetimes		1 batt lifetime	4 batt lifetimes
0.0	-	-	-	-	-	-			
2.5	1,307	7,639	13,577	231	1,350	2,400	242	1,413	2,511
5.0	9,223	53,901	95,794	1,944	11,360	20,189	2,619	15,304	27,198
7.5	24,973	145,943	259,371	9,455	55,257	98,203	16,269	95,074	168,966
10.0	51,418	300,487	534,028	26,001	151,952	270,050	45,531	266,084	472,886
12.5	95,855	560,178	995,553	49,903	291,632	518,290	88,146	515,128	915,489
15.0	172,514	1,008,173	1,791,732	90,733	530,246	942,358	144,123	842,253	1,496,858
17.5	281,085	1,642,658	2,919,344	158,996	929,172	1,651,331	213,283	1,246,428	2,215,162
20.0	400,282	2,339,247	4,157,327	245,632	1,435,471	2,551,130	293,719	1,716,493	3,050,564

Table 136 Annual and whole project lifetime costs of battery curtailment, without network reinforcement. Fairlie, Largs, Lochan Moor, 4-hour batteries

Battery capacity in excess of network headroom, MW	Fairlie, 4hr batteries			Largs, 4hr batteries			Lochan Moor, 4hr batteries		
	Annual cost, £	NPV whole lifetime costs, £		Annual cost, £	NPV whole lifetime costs, £		Annual cost, £	NPV whole lifetime costs, £	
		1 batt lifetime	4 batt lifetimes		1 batt lifetime	4 batt lifetimes		1 batt lifetime	4 batt lifetimes
0.0	-	-	-	-	-	-			
2.5	2,365	13,821	24,563	662	3,867	6,872	478	2,791	4,960
5.0	21,563	126,011	223,948	4,160	24,310	43,205	4,540	26,530	47,150
7.5	57,290	334,801	595,011	18,690	109,225	194,115	29,621	173,104	307,642
10.0	109,891	642,204	1,141,330	49,452	288,999	513,612	85,943	502,250	892,603
12.5	204,131	1,192,944	2,120,110	102,886	601,263	1,068,570	170,844	998,412	1,774,386
15.0	384,679	2,248,063	3,995,274	209,839	1,226,299	2,179,388	277,354	1,620,856	2,880,597
17.5	658,792	3,849,982	6,842,216	394,120	2,303,237	4,093,330	404,370	2,363,140	4,199,789
20.0	963,281	5,629,415	10,004,639	619,981	3,623,168	6,439,121	550,493	3,217,081	5,717,421

Table 137 Annual and whole project lifetime costs of battery curtailment, without network reinforcement, considering 'N' and 'N-1' network conditions, medium failure rate scenario. Armadale, Stranraer and Stevenston, 2-hour batteries

Battery capacity in excess of network headroom, MW	Armadale, 2hr batteries			Stranraer, 2hr batteries			Stevenston, 2hr batteries		
	Annual cost, £	NPV whole lifetime costs £		Annual cost, £	NPV whole lifetime costs, £		Annual cost, £	NPV whole lifetime costs £	
		1 batt lifetime	4 batt lifetimes		1 batt lifetime	4 batt lifetimes		1 batt lifetime	4 batt lifetimes
-17.5	-	-	-	4	22	39	- 0	- 0	- 1
-15.0	4	26	46	60	351	623	3	16	29
-12.5	26	151	268	250	1,460	2,595	66	386	687
-10.0	95	558	991	925	5,408	9,611	281	1,641	2,917
-7.5	226	1,319	2,345	2,391	13,974	24,835	818	4,779	8,493
-5.0	435	2,542	4,517	4,995	29,193	51,882	1,613	9,425	16,750
-2.5	814	4,758	8,456	8,862	51,791	92,043	2,817	16,460	29,252
0.0	1,852	10,821	19,232	13,815	80,735	143,483	4,835	28,256	50,216
2.5	3,219	18,814	33,437	19,454	113,688	202,047	7,058	41,247	73,304
5.0	5,561	32,499	57,757	25,381	148,328	263,610	9,825	57,415	102,038
7.5	9,666	56,490	100,394	34,869	203,773	362,148	16,241	94,914	168,683
10.0	19,104	111,642	198,411	56,675	331,210	588,629	26,236	153,323	272,486
12.5	33,063	193,222	343,395	93,202	544,671	967,994	47,100	275,251	489,178
15.0	53,420	312,186	554,819	142,911	835,170	1,484,270	79,527	464,758	825,971
17.5	82,903	484,487	861,033	211,995	1,238,899	2,201,781	127,259	743,703	1,321,714
20.0	125,906	735,793	1,307,657	302,584	1,768,301	3,142,638	220,298	1,287,420	2,288,012
25.0	286,022	1,671,514	2,970,627	524,919	3,067,624	5,451,804	478,588	2,796,867	4,970,613
30.0	508,759	2,973,189	5,283,973	761,984	4,453,035	7,913,967	771,214	4,506,976	8,009,831
35.0	744,401	4,350,277	7,731,344	1,031,471	6,027,914	10,712,853	1,031,367	6,027,310	10,711,779
40.0	1,001,571	5,853,183	10,402,320	1,331,174	7,779,380	13,825,572	1,274,206	7,446,462	13,233,907

Table 138 Annual and whole project lifetime costs of battery curtailment, without network reinforcement, considering 'N' and 'N-1' network conditions, medium failure rate scenario. Armadale, Stranraer and Stevenston, 4-hour batteries

Battery capacity in excess of network headroom, MW	Armadale, 4hr batteries			Stranraer, 4hr batteries			Stevenston, 4hr batteries		
	Annual cost, £	NPV whole lifetime costs £		Annual cost, £	NPV whole lifetime costs £		Annual cost, £	NPV whole lifetime costs £	
		1 batt lifetime	4 batt lifetimes		1 batt lifetime	4 batt lifetimes		1 batt lifetime	4 batt lifetimes
-17.5	-0	0	0	4	26	45	0	0	- 0
-15.0	12	69	123	152	887	1,576	25	145	258
-12.5	55	323	575	698	4,078	7,247	218	1,277	2,269
-10.0	189	1,104	1,961	2,478	14,482	25,738	905	5,290	9,402
-7.5	449	2,622	4,660	6,212	36,305	64,522	2,331	13,625	24,214
-5.0	917	5,356	9,519	12,762	74,580	132,544	4,676	27,327	48,566
-2.5	1,856	10,847	19,278	22,254	130,051	231,127	7,493	43,790	77,824
0.0	4,637	27,099	48,160	33,165	193,814	344,448	12,278	71,754	127,521
2.5	8,391	49,034	87,144	45,336	264,943	470,859	18,053	105,499	187,494
5.0	14,425	84,300	149,818	58,842	343,871	611,130	29,759	173,913	309,079
7.5	23,010	134,470	238,981	80,478	470,315	835,847	53,209	310,951	552,624
10.0	40,519	236,794	420,831	136,170	795,779	1,414,264	119,626	699,097	1,242,440
12.5	71,275	416,529	740,259	221,045	1,291,787	2,295,774	202,545	1,183,673	2,103,632
15.0	115,029	672,228	1,194,689	343,155	2,005,395	3,564,003	306,052	1,788,567	3,178,654
17.5	182,813	1,068,361	1,898,699	523,915	3,061,760	5,441,383	450,806	2,634,508	4,682,066
20.0	291,479	1,703,406	3,027,305	762,118	4,453,818	7,915,357	687,534	4,017,949	7,140,729
25.0	734,704	4,293,612	7,630,640	1,315,457	7,687,533	13,662,341	1,281,102	7,486,760	13,305,525
30.0	1,274,258	7,446,763	13,234,442	1,886,094	11,022,331	19,588,968	1,913,999	11,185,408	19,878,790
35.0	1,825,516	10,668,314	18,959,807	2,484,691	14,520,536	25,806,003	2,614,126	15,276,953	27,150,315
40.0	2,446,520	14,297,462	25,409,556	3,112,600	18,190,037	32,327,468	3,322,116	19,414,448	34,503,501

Chapter 8 Annex 4

Costs of residual curtailment, after network reinforcement

Table 139 Fairlie, Largs and Lochan Moor, after reinforcement. Average number of days per year of abnormal (N-1) conditions

Place	OHL length, km	Failure rate per yr per km	Average no. failures per year, one branch	Average no. failures per year, 2 branches	MTTR, days per failure	Average no of days of (N-1) conditions per yr
Fairlie	15.131	8.5%	1.29	2.57	5	12.9
Largs	16.463	8.5%	1.40	2.80	5	14.0
Lochan Moor	14.52	8.5%	1.23	2.47	5	12.3

Table 140 Residual curtailment costs after reinforcement. Fairlie.

Fairlie						
Battery capacity in excess of network headroom, MW	**" 'N-1' days": No. days/yr of N-1 conditions**	**Battery duration, hours**	**Average annual curtailment cost, £/ year**		**NPV of whole lifetime residual curtailment costs on reinforced network, £**	
			Original network, no reinforcement. "N" conditions, every day per year	**Residual curtailment costs on reinforced network, N-1 conditions occurring only " ' N-1' days" / year**	**1 batt lifetime**	**4 batt lifetimes**
0.0	12.9	2	-	-	-	-
2.5	12.9	2	1,307	46	269	478
5.0	12.9	2	9,223	325	1,898	3,373
7.5	12.9	2	24,973	879	5,139	9,133
10.0	12.9	2	51,418	1,811	10,581	18,804
12.5	12.9	2	95,855	3,375	19,725	35,056
15.0	12.9	2	172,514	6,075	35,500	63,091
17.5	12.9	2	281,085	9,898	57,842	102,797
20.0	12.9	2	400,282	14,095	82,371	146,390
0.0	12.9	4	0	0	0	0
2.5	12.9	4	2,365	83	487	865
5.0	12.9	4	21,563	759	4,437	7,886
7.5	12.9	4	57,290	2,017	11,789	20,952
10.0	12.9	4	109,891	3,870	22,614	40,189
12.5	12.9	4	204,131	7,188	42,007	74,654
15.0	12.9	4	384,679	13,545	79,160	140,683
17.5	12.9	4	658,792	23,198	135,567	240,931
20.0	12.9	4	963,281	33,919	198,226	352,288

Table 141 Residual curtailment costs after reinforcement. Largs

Largs						
Battery capacity in excess of network headroom, MW	" 'N-1' days": No. days/yr of N-1 conditions	Battery duration, hours	Average annual curtailment cost, £/ year		NPV of whole lifetime residual curtailment costs on reinforced network, £	
			Original network, no reinforcement. "N" conditions, every day per year	Residual curtailment costs on reinforced network, N-1 conditions occurring only " ' N-1' days" / year	1 batt lifetime	4 batt lifetimes
0.0	14.0	2	-	-	-	-
2.5	14.0	2	231	9	52	92
5.0	14.0	2	1,944	74	435	773
7.5	14.0	2	9,455	362	2,117	3,762
10.0	14.0	2	26,001	996	5,822	10,346
12.5	14.0	2	49,903	1,912	11,173	19,857
15.0	14.0	2	90,733	3,476	20,315	36,104
17.5	14.0	2	158,996	6,091	35,599	63,266
20.0	14.0	2	245,632	9,411	54,996	97,740
0.0	14.0	4	-	-	-	-
2.5	14.0	4	662	25	148	263
5.0	14.0	4	4,160	159	931	1,655
7.5	14.0	4	18,690	716	4,185	7,437
10.0	14.0	4	49,452	1,895	11,072	19,678
12.5	14.0	4	102,886	3,942	23,036	40,939
15.0	14.0	4	209,839	8,039	46,982	83,497
17.5	14.0	4	394,120	15,100	88,242	156,825
20.0	14.0	4	619,981	23,753	138,812	246,697

Table 142 Residual curtailment costs after reinforcement. Lochan Moor

Lochan Moor						
Battery capacity in excess of network headroom, MW	" 'N-1' days": No. days/yr of N-1 conditions	Battery duration, hours	Average annual curtailment cost, £/ year		NPV of whole lifetime residual curtailment costs on reinforced network, £	
			Original network, no reinforcement. "N" conditions, every day per year	Residual curtailment costs on reinforced network, N-1 conditions occurring only " ' N-1' days" / year	1 batt lifetime	4 batt lifetimes
0.0	12.3	2	-	-	-	-
2.5	12.3	2	242	8	48	85
5.0	12.3	2	2,619	88	517	919
7.5	12.3	2	16,269	550	3,213	5,709
10.0	12.3	2	45,531	1,539	8,991	15,979
12.5	12.3	2	88,146	2,979	17,406	30,935
15.0	12.3	2	144,123	4,870	28,460	50,580
17.5	12.3	2	213,283	7,207	42,118	74,852
20.0	12.3	2	293,719	9,925	58,001	103,080
0.0	12.3	4				
2.5	12.3	4	478	16	94	168
5.0	12.3	4	4,540	153	896	1,593
7.5	12.3	4	29,621	1,001	5,849	10,395
10.0	12.3	4	85,943	2,904	16,971	30,162
12.5	12.3	4	170,844	5,773	33,737	59,957
15.0	12.3	4	277,354	9,372	54,770	97,337
17.5	12.3	4	404,370	13,664	79,852	141,913
20.0	12.3	4	550,493	18,601	108,707	193,195

Table 143 Residual curtailment costs after reinforcement. Armadale

Battery capacity in excess of network headroom, MW	No days 'N-1'	Armadale, 2 hr batteries						Armadale, 4 hr batteries					
		Annual curtailment costs, £				NPV whole lifetime curt costs: sum N & N-1 costs, £		Annual curtailment costs, £				NPV whole lifetime curt costs: sum N & N-1 costs, £	
		N conditions	N, adjusted[116]	N-1 conditions all scenarios	Sum N & N-1 curt costs	1 batt life	4 batt lives	N conditions	N, adjusted	N-1 conditions all scenarios	Sum N & N-1 curt costs	1 batt life	4 batt lives
0	6.9	-	-	-	-	-	-	-	-	-	-	-	-
2.5	6.9	-	-	-	-	-	-	-	-	-	-	-	-
5	6.9	-	0	7	7	43	76	-	-	24	24	143	254
7.5	6.9	-	0	36	36	209	371	-	-	76	76	442	785
10	6.9	-	0	127	127	743	1,320	-	-	234	234	1,369	2,433
12.5	6.9	-	0	275	275	1,608	2,858	-	-	559	559	3,268	5,808
15	6.9	-	0	503	503	2,942	5,229	-	-	1,049	1,049	6,132	10,897
17.5	6.9	-	0	935	935	5,466	9,715	-	-	2,080	2,080	12,154	21,600
20	6.9	-	0	1,891	1,891	11,048	19,635	-	-	4,583	4,583	26,784	47,600
25	6.9	778	763	4,743	5,506	32,177	57,186	2,401	2,356	12,550	14,906	87,111	154,815
30	6.9	11,264	11,051	8,507	19,557	114,294	203,124	19,421	19,053	22,336	41,390	241,880	429,872
35	6.9	41,998	41,204	12,826	54,030	315,750	561,154	83,793	82,209	32,781	114,990	672,002	1,194,286
40	6.9	111,258	109,155	17,634	126,790	740,959	1,316,838	239,611	235,081	44,168	279,249	1,631,931	2,900,281

[116] N costs adjusted for fewer than 365.25 days a year of N conditions when also counting curtailment costs under 'N-1' conditions

Table 144 Residual curtailment costs after reinforcement. Stranraer

Battery capacity in excess of network headroom, MW	No days 'N-1'	Stranraer, 2 hr batteries: Annual curtailment costs, £: N conditions	N, adjusted [117]	N-1 conditions all scenarios	Sum N & N-1 curt costs	NPV whole lifetime curt costs: sum N & N-1 costs, £: 1 batt life	4 batt lives	Stranraer, 4 hr batteries: Annual curtailment costs, £: N conditions	N, adjusted	N-1 conditions all scenarios	Sum N & N-1 curt costs	NPV whole lifetime curt costs: sum N & N-1 costs, £: 1 batt life	4 batt lives
0	23.2	-	-	-	-	-	-	-	-	-0	-0	-0	-0
2.5	23.2	-	-	6	6	33	59	-	-	8	8	45	80
5	23.2	-	-	66	66	386	686	-	-	166	166	972	1,727
7.5	23.2	-	-	316	316	1,848	3,285	-	-	794	794	4,637	8,241
10	23.2	-	-	1,247	1,247	7,289	12,954	-	-	3,243	3,243	18,953	33,683
12.5	23.2	-	-	3,082	3,082	18,014	32,015	-	-	7,887	7,887	46,090	81,911
15	23.2	-	-	5,756	5,756	33,641	59,786	-	-	14,806	14,806	86,524	153,771
17.5	23.2	-	-	9,487	9,487	55,443	98,534	-	-	24,869	24,869	145,337	258,293
20	23.2	-	-	14,504	14,504	84,763	150,642	-	-	38,359	38,359	224,172	398,400
25	23.2	-48	-45	26,823	26,779	156,495	278,125	382	358	70,085	70,442	411,666	731,616
30	23.2	19,777	18,523	40,657	59,180	345,850	614,648	54,552	51,092	104,726	155,818	910,602	1,618,328
35	23.2	95,216	89,177	57,161	146,338	855,200	1,519,868	235,678	220,731	142,764	363,494	2,124,260	3,775,250
40	23.2	219,674	205,741	75,362	281,103	1,642,769	2,919,540	581,867	544,964	181,390	726,354	4,244,813	7,543,912

[117] N costs adjusted for fewer than 365.25 days a year of N conditions when also counting curtailment costs under 'N-1' conditions

Table 145 Residual curtailment costs after reinforcement. Stevenston

Battery capacity in excess of network headroom, MW	No days 'N-1'	Stevenston, 2 hr batteries						Stevenston, 4 hr batteries					
		Annual curtailment costs, £				NPV whole lifetime curt costs: sum N & N-1 costs, £		Annual curtailment costs, £				NPV whole lifetime curt costs: sum N & N-1 costs, £	
		N conditions	N, adjusted[118]	N-1 conditions all scenarios	Sum N & N-1 curt costs	1 batt life	4 batt lives	N conditions	N, adjusted	N-1 conditions all scenarios	Sum N & N-1 curt costs	1 batt life	4 batt lives
0	9.3	-	-	-	-	-	-	-	-	-0	-0	-0	-0
2.5	9.3	-	-	-	-	-	-	-	-	0	0	0	0
5	9.3	-	-	2	2	13	24	-	-	52	52	303	538
7.5	9.3	-	-	30	30	177	314	-	-	234	234	1,367	2,430
10	9.3	-	-	112	112	653	1,160	-	-	877	877	5,126	9,110
12.5	9.3	-	-	323	323	1,887	3,354	-	-	1,946	1,946	11,372	20,210
15	9.3	-	-	657	657	3,840	6,825	-	-	3,500	3,500	20,452	36,348
17.5	9.3	-	-	1,367	1,367	7,991	14,202	-	-	5,843	5,843	34,145	60,682
20	9.3	-	-	2,941	2,941	17,187	30,545	-	-	10,226	10,226	59,759	106,204
25	9.3	497	484	7,304	7,788	45,511	80,882	7,159	6,978	21,579	28,557	166,886	296,590
30	9.3	9,055	8,825	12,961	21,786	127,320	226,274	50,003	48,737	35,350	84,087	491,405	873,328
35	9.3	20,636	20,113	19,405	39,518	230,945	410,437	157,647	153,654	50,992	204,646	1,195,950	2,125,450
40	9.3	101,478	98,908	26,230	125,138	731,307	1,299,684	390,433	380,545	68,049	448,594	2,621,585	4,659,101

[118] N costs adjusted for fewer than 365.25 days a year of N conditions when also counting curtailment costs under 'N-1' conditions

Chapter 8 Annex 5

Total costs of reinforcement option

Table 146 Fairlie: Total costs of reinforcement option

Battery capacity, in excess of network headroom, MW	Fairlie									
	Batt capacity, MW	Reinforce-ment CAPEX costs, £	2 hour batteries				4 hour batteries			
			Cost of residual curtailment, after reinforcement: whole project lifetime costs, £		Total cost of reinforcement, including reinforcement and residual curtailment: whole project lifetime cost, £		Cost of residual curtailment, after reinforcement: whole project lifetime costs, £		Total cost of reinforcement, including reinforcement and residual curtailment: whole project lifetime cost, £	
			1 batt lifetime	4 batt lifetimes	Reinforcement + residual curt. costs, 1 batt lifetime	Reinforcement + residual curt. costs, 4 batt lifetimes	1 batt lifetime	4 batt lifetimes	Reinforcement + residual curt. costs, 1 batt lifetime	Reinforcement + residual curt. costs,4 batt lifetimes
0	7.0	747,532	-	-	**747,532**	**747,532**	-	-	**747,532**	**747,532**
2.5	9.5	747,532	269	478	**747,801**	**748,010**	487	865	**748,019**	**748,397**
5	12.0	747,532	1,898	3,373	**749,430**	**750,906**	4,437	7,886	**751,970**	**755,418**
7.5	14.5	747,532	5,139	9,133	**752,671**	**756,666**	11,789	20,952	**759,322**	**768,484**
10	17.0	747,532	10,581	18,804	**758,113**	**766,337**	22,614	40,189	**770,146**	**787,721**
12.5	19.5	747,532	19,725	35,056	**767,258**	**782,588**	42,007	74,654	**789,539**	**822,187**
15	22.0	747,532	35,500	63,091	**783,033**	**810,624**	79,160	140,683	**826,692**	**888,216**
17.5	24.5	747,532	57,842	102,797	**805,374**	**850,330**	135,567	240,931	**883,100**	**988,464**
20	27.0	747,532	82,371	146,390	**829,903**	**893,922**	198,226	352,288	**945,758**	**1,099,820**

Table 147 Largs: Total costs of reinforcement option

Battery capacity, in excess of network headroom, MW	**Largs**									
	Batt capacity, MW	**Reinforce-ment CAPEX costs, £**	**2 hour batteries**				**4 hour batteries**			
			Cost of residual curtailment, after reinforcement: whole project lifetime costs, £		**Total cost of reinforcement, including reinforcement and residual curtailment: whole project lifetime cost, £**		**Cost of residual curtailment, after reinforcement: whole project lifetime costs, £**		**Total cost of reinforcement, including reinforcement and residual curtailment: whole project lifetime cost, £**	
			1 batt lifetime	**4 batt lifetimes**	**Reinforcement + residual curt. costs, 1 batt lifetime**	**Reinforcement + residual curt. costs, 4 batt lifetimes**	**1 batt lifetime**	**4 batt lifetimes**	**Reinforcement + residual curt. costs, 1 batt lifetime**	**Reinforcement + residual curt. costs, 4 batt lifetimes**
0	7.2	813,339	-	-	**813,339**	**813,339**	-	-	**813,339**	**813,339**
2.5	9.7	813,339	52	92	**813,390**	**813,431**	148	263	**813,487**	**813,602**
5	12.2	813,339	435	773	**813,774**	**814,112**	931	1,655	**814,270**	**814,994**
7.5	14.7	813,339	2,117	3,762	**815,456**	**817,101**	4,185	7,437	**817,523**	**820,776**
10	17.2	813,339	5,822	10,346	**819,160**	**823,685**	11,072	19,678	**824,411**	**833,016**
12.5	19.7	813,339	11,173	19,857	**824,512**	**833,195**	23,036	40,939	**836,374**	**854,278**
15	22.2	813,339	20,315	36,104	**833,654**	**849,442**	46,982	83,497	**860,321**	**896,836**
17.5	24.7	813,339	35,599	63,266	**848,937**	**876,605**	88,242	156,825	**901,581**	**970,163**
20	27.2	813,339	54,996	97,740	**868,335**	**911,078**	138,812	246,697	**952,150**	**1,060,036**

Table 148 Lochan Moor: Total costs of reinforcement option

Battery capacity, in excess of network headroom, MW	Lochan Moor									
	Batt capacity, MW	Reinforce-ment CAPEX costs, £	2 hour batteries				4 hour batteries			
			Cost of residual curtailment, after reinforcement: whole project lifetime costs, £		Total cost of reinforcement, including reinforcement and residual curtailment: whole project lifetime cost, £		Cost of residual curtailment, after reinforcement: whole project lifetime costs, £		Total cost of reinforcement, including reinforcement and residual curtailment: whole project lifetime cost, £	
			1 batt lifetime	4 batt lifetimes	Reinforcement + residual curt. costs, 1 batt lifetime	Reinforcement + residual curt. costs, 4 batt lifetimes	1 batt lifetime	4 batt lifetimes	Reinforcement + residual curt. costs, 1 batt lifetime	Reinforcement + residual curt. costs, 4 batt lifetimes
0	Not modelled									
2.5	2.5	717,347	48	85	**717,394**	**717,431**	94	168	**717,441**	**717,514**
5	5	717,347	517	919	**717,864**	**718,266**	896	1,593	**718,243**	**718,940**
7.5	7.5	717,347	3,213	5,709	**720,559**	**723,056**	5,849	10,395	**723,196**	**727,742**
10	10	717,347	8,991	15,979	**726,338**	**733,326**	16,971	30,162	**734,318**	**747,508**
12.5	12.5	717,347	17,406	30,935	**734,753**	**748,281**	33,737	59,957	**751,083**	**777,304**
15	15	717,347	28,460	50,580	**745,807**	**767,926**	54,770	97,337	**772,116**	**814,684**
17.5	17.5	717,347	42,118	74,852	**759,464**	**792,198**	79,852	141,913	**797,198**	**859,260**
20	20	717,347	58,001	103,080	**775,348**	**820,427**	108,707	193,195	**826,054**	**910,541**

Table 149 Armadale: Total costs of reinforcement option

Battery capacity, in excess of network headroom, MW	Armadale									
	Batt capacity, MW	Reinforce-ment CAPEX costs, £	2 hour batteries				4 hour batteries			
			Cost of residual curtailment, after reinforcement: whole project lifetime costs, £		Total cost of reinforcement, including reinforcement and residual curtailment: whole project lifetime cost, £		Cost of residual curtailment, after reinforcement: whole project lifetime costs, £		Total cost of reinforcement, including reinforcement and residual curtailment: whole project lifetime cost, £	
			1 batt lifetime	4 batt lifetimes	Reinforcement + residual curt. costs, 1 batt lifetime	Reinforcement + residual curt. costs, 4 batt lifetimes	1 batt lifetime	4 batt lifetimes	Reinforcement + residual curt. costs, 1 batt lifetime	Reinforcement + residual curt. costs, 4 batt lifetimes
0	22.5	90,903	- 0	- 0	**90,903**	**90,903**	-	-	**90,903**	**90,903**
2.5	25	90,903	0	0	**90,903**	**90,903**	-	-	**90,903**	**90,903**
5	27.5	90,903	43	76	**90,946**	**90,980**	143	254	**91,046**	**91,157**
7.5	30	90,903	209	371	**91,112**	**91,274**	442	785	**91,345**	**91,688**
10	32.5	90,903	743	1,320	**91,646**	**92,223**	1,369	2,433	**92,273**	**93,337**
12.5	35	90,903	1,608	2,858	**92,511**	**93,761**	3,268	5,808	**94,172**	**96,712**
15	37.5	90,903	2,942	5,229	**93,846**	**96,132**	6,132	10,897	**97,035**	**101,801**
17.5	40	90,903	5,466	9,715	**96,370**	**100,618**	12,154	21,600	**103,057**	**112,503**
20	42.5	90,903	11,048	19,635	**101,952**	**110,538**	26,784	47,600	**117,687**	**138,503**
25	47.5	90,903	32,177	57,186	**123,081**	**148,089**	87,111	154,815	**178,015**	**245,718**
30	52.5	90,903	114,294	203,124	**205,197**	**294,027**	241,880	429,872	**332,784**	**520,775**
35	57.5	90,903	315,750	561,154	**406,654**	**652,057**	672,002	1,194,286	**762,905**	**1,285,190**
40	62.5	90,903	740,959	1,316,838	**831,862**	**1,407,741**	1,631,931	2,900,281	**1,722,835**	**2,991,184**

Table 150 Stranraer: Total costs of reinforcement option

Battery capacity, in excess of network headroom, MW	Batt capacity, MW	Stranraer								
		Reinforce-ment CAPEX costs, £	2 hour batteries				4 hour batteries			
			Cost of residual curtailment, after reinforcement: whole project lifetime costs, £		Total cost of reinforcement, including reinforcement and residual curtailment: whole project lifetime cost, £		Cost of residual curtailment, after reinforcement: whole project lifetime costs, £		Total cost of reinforcement, including reinforcement and residual curtailment: whole project lifetime cost, £	
			1 batt lifetime	4 batt lifetimes	Reinforcement + residual curt. costs, 1 batt lifetime	Reinforcement + residual curt. costs, 4 batt lifetimes	1 batt lifetime	4 batt lifetimes	Reinforcement + residual curt. costs, 1 batt lifetime	Reinforcement + residual curt. costs, 4 batt lifetimes
0	27.7	746,001	-	-	**746,001**	**746,001**	- 0	- 0	**746,001**	**746,001**
2.5	30.2	746,001	33	59	**746,034**	**746,060**	45	80	**746,046**	**746,081**
5	32.7	746,001	386	686	**746,387**	**746,687**	972	1,727	**746,973**	**747,728**
7.5	35.2	746,001	1,848	3,285	**747,849**	**749,286**	4,637	8,241	**750,638**	**754,242**
10	37.7	746,001	7,289	12,954	**753,290**	**758,955**	18,953	33,683	**764,954**	**779,684**
12.5	40.2	746,001	18,014	32,015	**764,015**	**778,015**	46,090	81,911	**792,091**	**827,912**
15	42.7	746,001	33,641	59,786	**779,641**	**805,787**	86,524	153,771	**832,525**	**899,772**
17.5	45.2	746,001	55,443	98,534	**801,444**	**844,535**	145,337	258,293	**891,338**	**1,004,294**
20	47.7	746,001	84,763	150,642	**830,764**	**896,642**	224,172	398,400	**970,173**	**1,144,401**
25	52.7	746,001	156,495	278,125	**902,496**	**1,024,126**	411,666	731,616	**1,157,667**	**1,477,616**
30	57.7	746,001	345,850	614,648	**1,091,851**	**1,360,649**	910,602	1,618,328	**1,656,603**	**2,364,329**
35	62.7	746,001	855,200	1,519,868	**1,601,201**	**2,265,869**	2,124,260	3,775,250	**2,870,261**	**4,521,251**
40	67.7	746,001	1,642,769	2,919,540	**2,388,769**	**3,665,541**	4,244,813	7,543,912	**4,990,813**	**8,289,913**

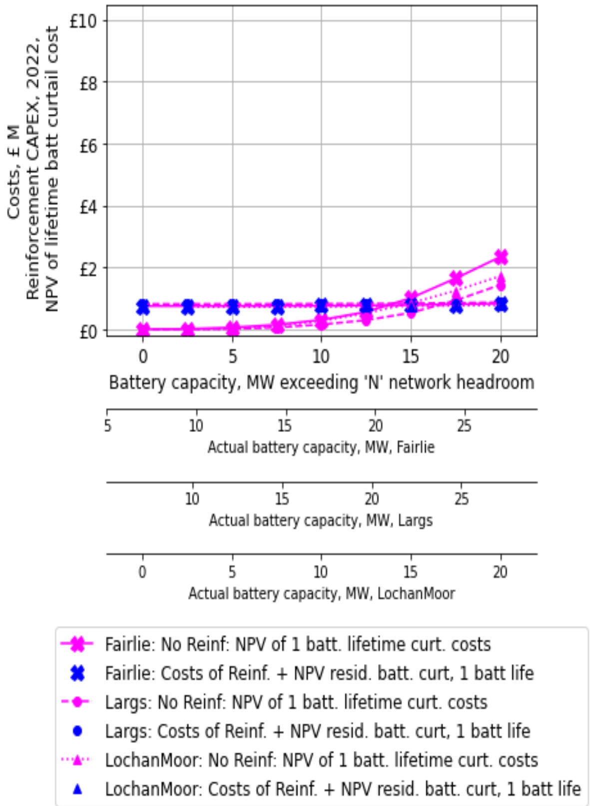
Table 151 Stevenston: Total costs of reinforcement option

Battery capacity, in excess of network headroom, MW	Stevenston									
	Batt capacity, MW	Reinforce-ment CAPEX costs, £	2 hour batteries				4 hour batteries			
			Cost of residual curtailment, after reinforcement: whole project lifetime costs, £		Total cost of reinforcement, including reinforcement and residual curtailment: whole project lifetime cost, £		Cost of residual curtailment, after reinforcement: whole project lifetime costs, £		Total cost of reinforcement, including reinforcement and residual curtailment: whole project lifetime cost, £	
			1 batt lifetime	4 batt lifetimes	Reinforcement + residual curt. costs, 1 batt lifetime	Reinforcement + residual curt. costs, 4 batt lifetimes	1 batt lifetime	4 batt lifetimes	Reinforcement + residual curt. costs, 1 batt lifetime	Reinforcement + residual curt. costs, 4 batt lifetimes
0	22.6	180,819	-	-	**180,819**	**180,819**	- 0	- 0	**180,819**	**180,819**
2.5	25.1	180,819	-	-	**180,819**	**180,819**	0	0	**180,819**	**180,819**
5	27.6	180,819	13	24	**180,832**	**180,842**	303	538	**181,121**	**181,357**
7.5	30.1	180,819	177	314	**180,996**	**181,133**	1,367	2,430	**182,186**	**183,249**
10	32.6	180,819	653	1,160	**181,471**	**181,979**	5,126	9,110	**185,945**	**189,929**
12.5	35.1	180,819	1,887	3,354	**182,706**	**184,173**	11,372	20,210	**192,190**	**201,029**
15	37.6	180,819	3,840	6,825	**184,659**	**187,644**	20,452	36,348	**201,271**	**217,167**
17.5	40.1	180,819	7,991	14,202	**188,810**	**195,021**	34,145	60,682	**214,964**	**241,501**
20	42.6	180,819	17,187	30,545	**198,006**	**211,363**	59,759	106,204	**240,577**	**287,022**
25	47.6	180,819	45,511	80,882	**226,329**	**261,700**	166,886	296,590	**347,704**	**477,409**
30	52.6	180,819	127,320	226,274	**308,139**	**407,093**	491,405	873,328	**672,223**	**1,054,147**
35	57.6	180,819	230,945	410,437	**411,763**	**591,255**	1,195,950	2,125,450	**1,376,768**	**2,306,269**
40	62.6	180,819	731,307	1,299,684	**912,126**	**1,480,503**	2,621,585	4,659,101	**2,802,404**	**4,839,920**

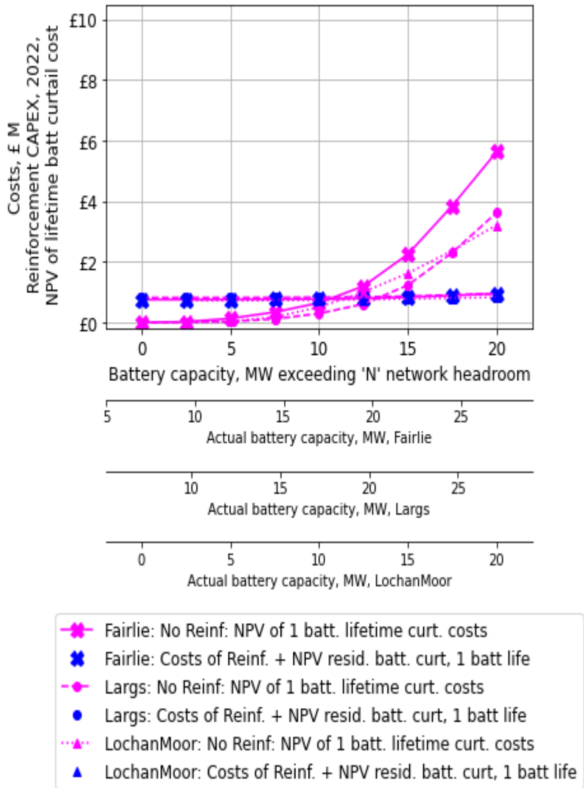
Chapter 8 Annex 6

Results: cost comparison of “Reinforce” and “do not reinforce options”

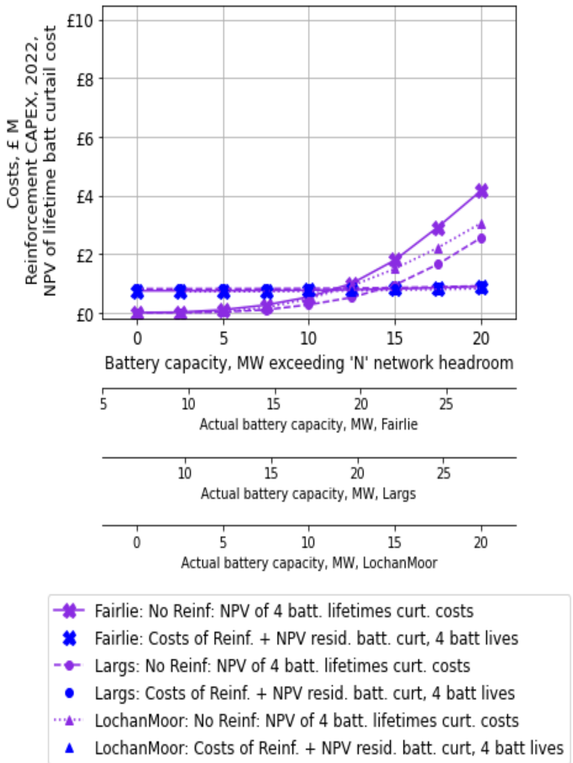
Figures are displayed on the following page.



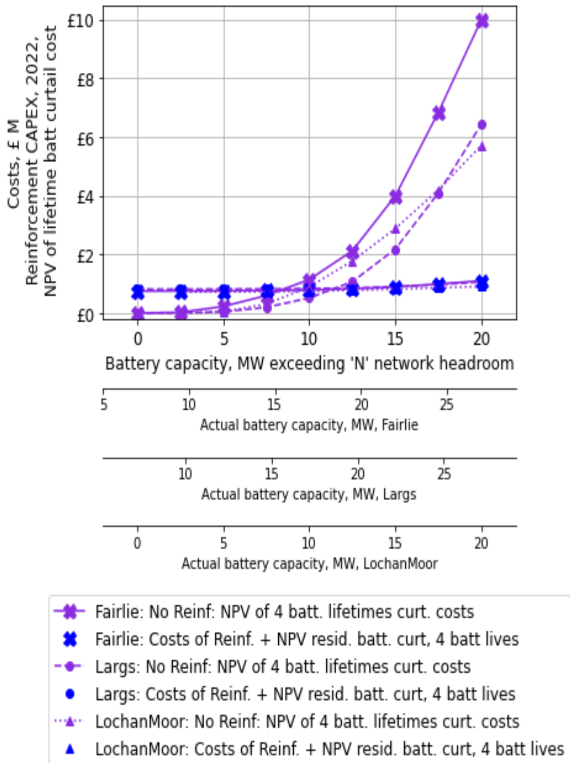
(c) 2hr batteries, 1 lifetime scenario



(d) 4hr batteries, 1 lifetime scenario

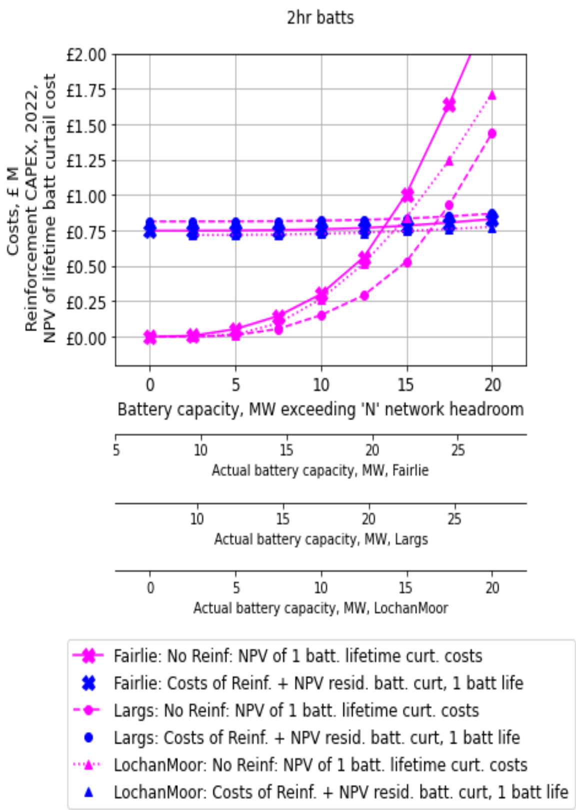


(c) 2hr batteries, 4 lifetimes scenario

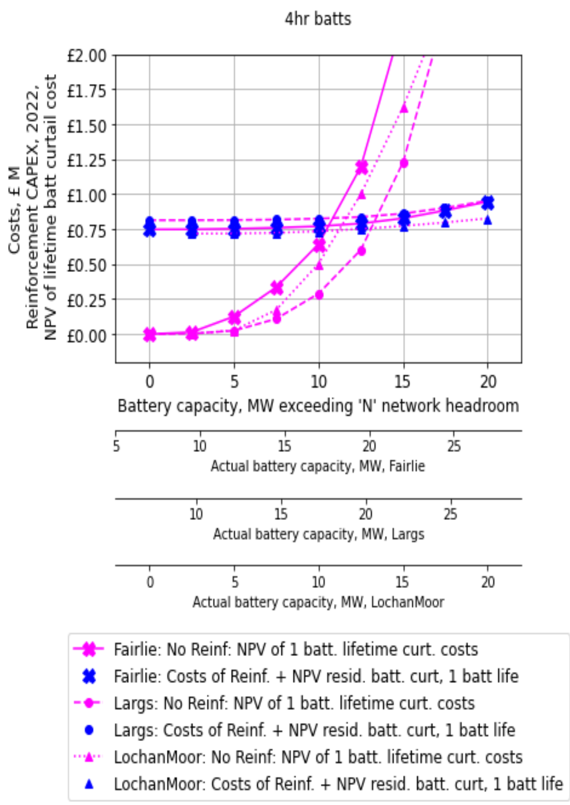


(d) 4hr batteries, 4 lifetimes scenario

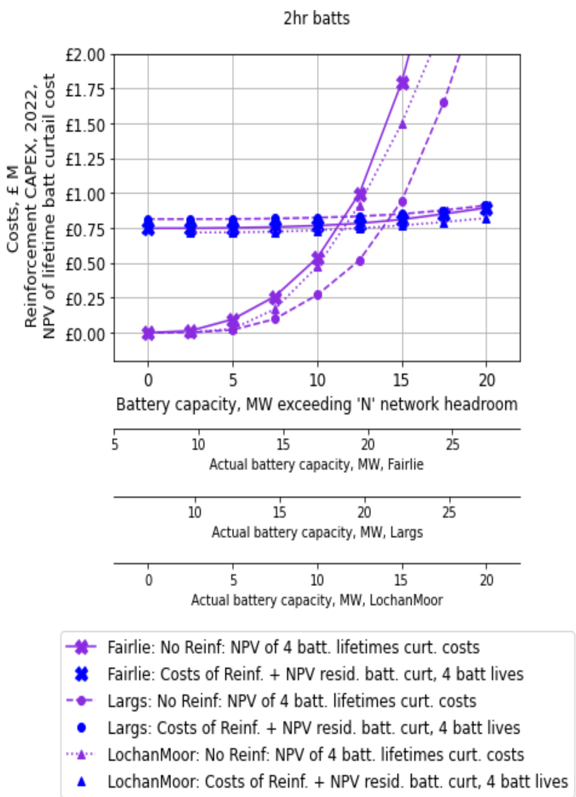
Figure 215 Costs of “reinforce” and “do not reinforce” options, Fairlie, Largs and Lochan Moor.

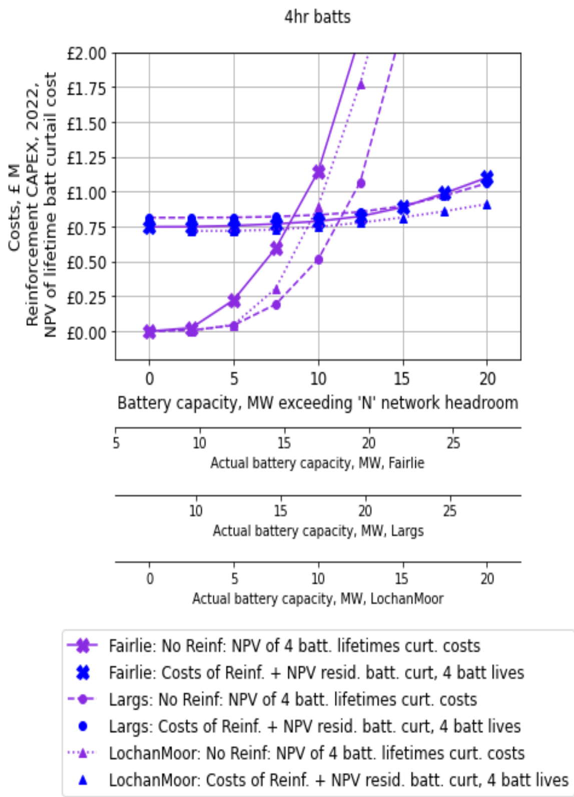


(a) 2hr batteries, 1 lifetime scenario



(b) 4hr batteries, 1 lifetime scenario

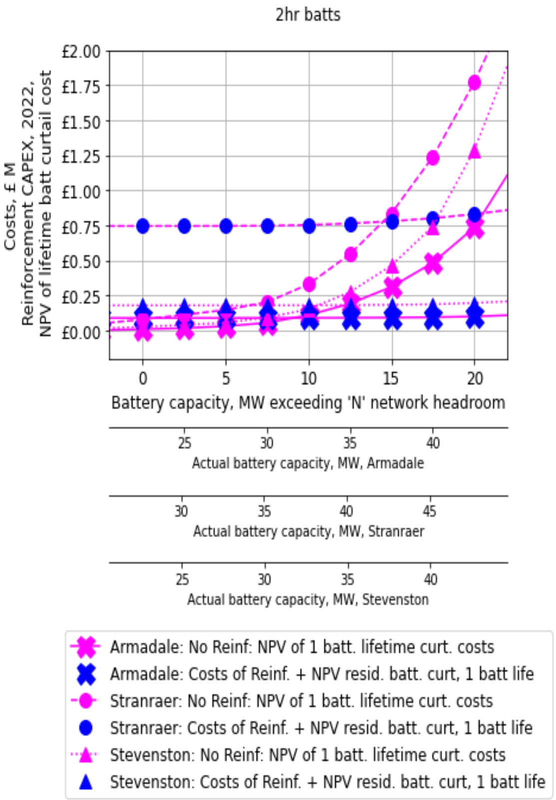




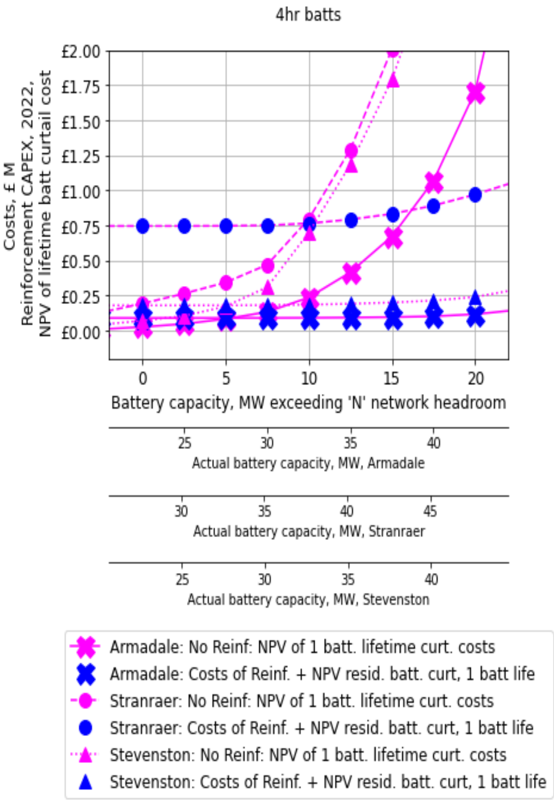
(c) 2hr batteries, 4 lifetimes scenario

(d) 4hr batteries, 4 lifetimes scenario

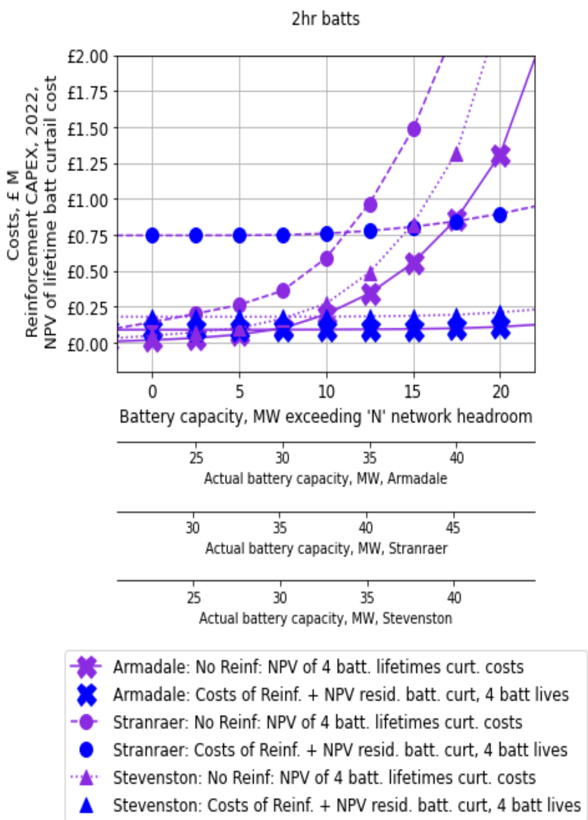
Figure 216 Costs of “reinforce” and “do not reinforce” options, Fairlie, Largs and Lochan Moor (larger scale charts)



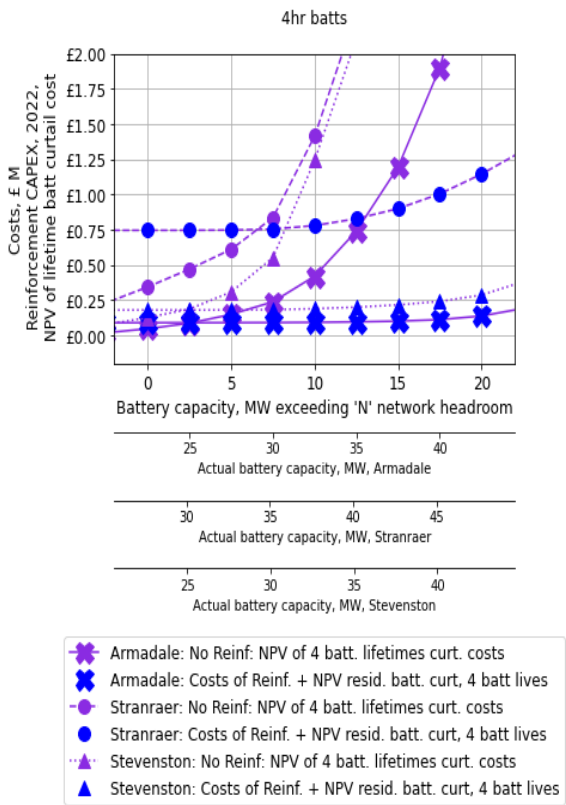
(a) 2hr batteries, 1 lifetime scenario



(b) 4hr batteries, 1 lifetime scenario



(c) 2hr batteries, 4 lifetimes scenario



(d) 4hr batteries, 4 lifetimes scenario

Figure 217 Costs of “reinforce” and “do not reinforce” options, Armadale, Stranraer and Stevenston (larger scale charts)

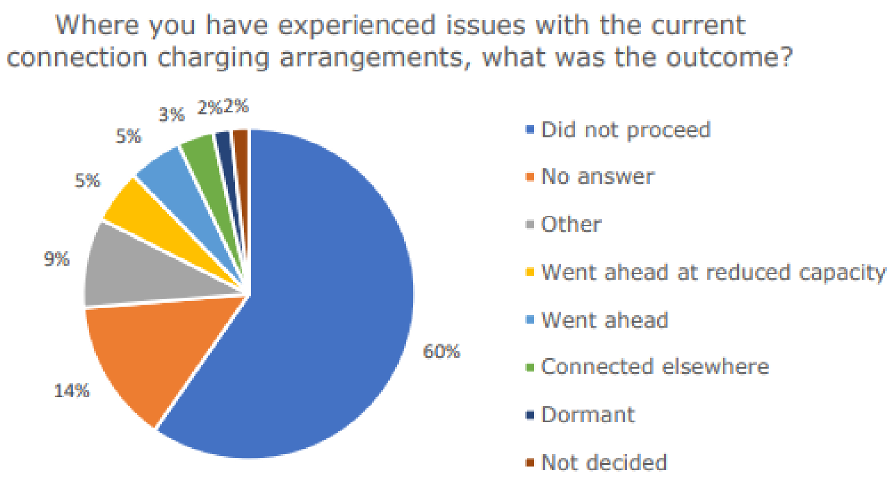
Chapter 8 Annex 7

Stakeholder consultation: developers' response to liability for network reinforcement charges.

7.1 Stakeholder feedback on project outcomes (BEIS, Ofgem, 2019)

Source: [255] Page 25-26

Figure 4 - Stakeholder feedback on project outcomes[29]



'The ENA call for evidence is available here: https://www.energynetworks.org/greenrecovery
' Source: SCR Challenge Group, Charging Futures, BEIS OLEV stakeholder distribution list, 57 responses, 2019)

25

Figure 218 Stakeholder feedback (Ofgem): developers' actions when connections charges were necessary. (Survey of EV charging stations, 57 responses), 2019.

ofgem

Making a positive difference
for energy consumers

Figure 5 - Stakeholder feedback on issues experienced with connection to distribution networks[30]

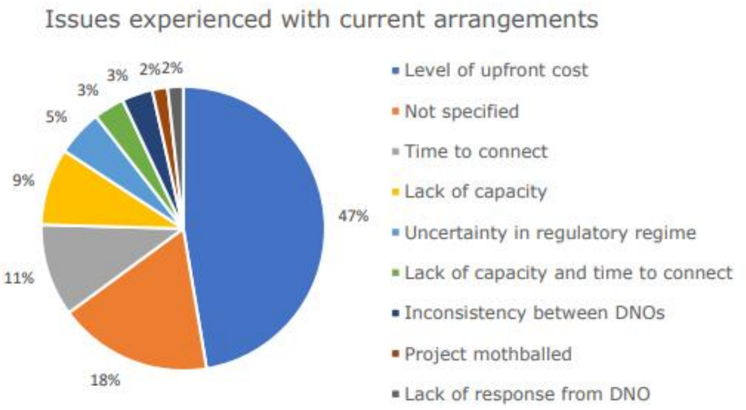


Figure 219 Stakeholder feedback (reproduced from Ofgem): "Issues experienced with current arrangements [for gaining a Distribution Network connection]. (Survey of EV charging stations, 57 responses), 2019.

7.2 Stakeholder feedback survey, further results (NESO)

Source: NESO, Charging Futures. Access and Forward-looking charges SCR Challenge Group. 25 November 2019. [277]

Access and forward-looking charges reform | National Energy System Operator (lists meetings). PowerPoint presentation template (the ppt)

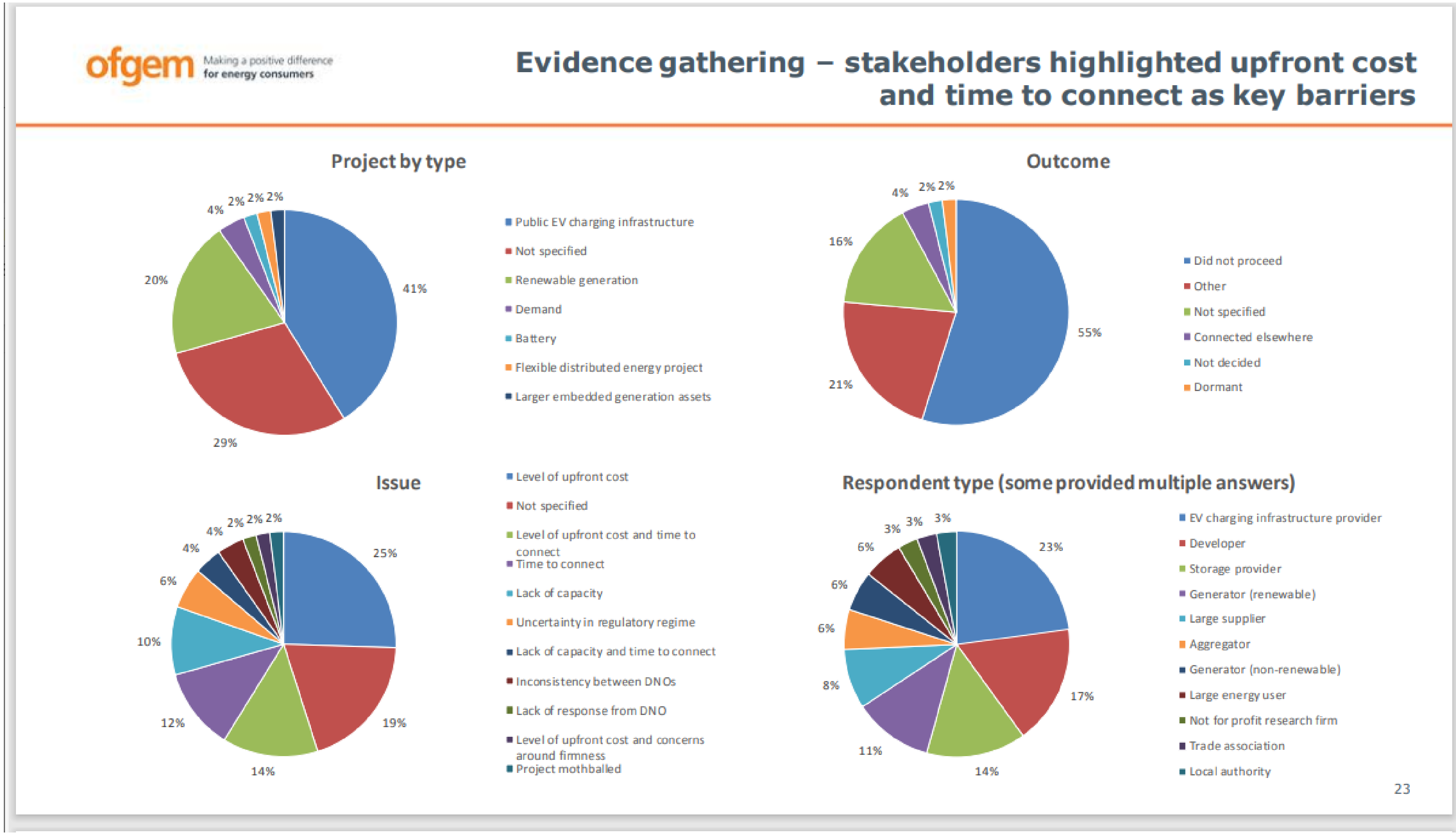


Figure 220 Stakeholder feedback survey, reproduced from Ofgem. "Evidence gathering – stakeholders highlighted upfront cost and time to connect as key barriers". 2019

Annexes to Chapter 9 Conclusions

Contents of Annexes to Chapter 9

Chapter 9 Annex 1

Critique of the ESO's recent changes to assumptions about likely battery actions, incorporated into its Construction Planning Assumptions

Table 152 ESO's revised assumptions regarding battery actions, December 2023 [100], [101]

ESO's assumption	Evaluation from this work and the literature
(1) (a) A battery does not typically export at times of peak generation	**This work *found to the contrary* in the case of *wind generation*.** Exports are likely to continue to occur during periods of high wind generation (Chapter 5, Section 5.3.3), generally at times coinciding with diurnal pattern of high system price (Chapter 4, Section 4.7.2), which are sometimes also times of high system demand and often local demands (Chapter 6 Section 6.7.2.2). A battery located behind a Transmission constraint (e.g. in Scotland), caused partly or wholly by wind-generation, would, at present, be exposed to a price signal encouraging export at time of high system demand. However, battery exports at such times of high wind would be unable to contribute to the wider system demand beyond the constraint (e.g. to demand in England and Wales). In contrast, **this work found that this ESO's assumption is likely to hold for solar generation**: battery exports were unusual around midday and early afternoon, the times of peak solar generation, times at which battery imports were more common (Chapter 4, Section 4.7.3, and Chapter 6, Section 6.2.7.1). **This work did not investigate interaction between likely battery action and hydro generation.**
(1) (b) A battery does not typically import at times of peak demand	**This work *agrees* with the *strict wording*, but *found against* some *closely-related scenarios.*** This work found that batteries generally do not import at times of *peak demand* (in late afternoons or early evenings, times when battery exports are usual, Chapter 4, Section 4.7.3). However, batteries may import at times of local or regional *high demand*, particularly in locations with a fairly flat daytime demand profile, and absence of solar generation, where a price-driven midday battery imports would occur at a time of high local demand (Chapter 6 Section 6.7.2.2). Depending on the sizing of the battery, such behaviour may exacerbate maximum network import flows.
(2) A battery does not act	**This work generally concurs, with caveats.** There is a variety of revenue streams and actions available to batteries, which would encourage diversification of

ESO's assumption	**Evaluation from this work and the literature**
uniformly at all times	actions (described in Chapter 3). Even for batteries engaged in wholesale trades, at times similar levels of revenue may be accrued from differing actions (e.g. Chapter 4, Section 4.7.4, in the "winter" case study period). Thus, a high level of coincidence of exports around times of short-lasting late afternoon / early evening peaks in system demand and price may be expected, but significant diversification of battery actions at other times. Inspection of real grid-connected batteries wholesale actions during 2022 (Annexes to Chapter 3, Annex 4, and Annexes to Chapter 4, Annex 5) concurred with the above expectation.
(3) [A battery] operates for relatively short periods	**This work concurs, for the current battery fleet.**
(4) Modelling should be aligned across transmission and distribution	**Not investigated, but considered a very sensible aim.**

Chapter 9 Annex 2

Comments on data availability (and lack of)

The availability of relevant datasets is fundamental to any work to model future electricity and other energy needs, and ways in which they might be met.

Wider availability of applicable datasets, ideally free at the point of use, and in formats for easy download, would aid other researchers, academic and otherwise, to produce work of greater scope, relevance, and quality, and in a more time- and cost-efficient manner.

Given the scale and pace of work that is required for our electricity system to decarbonise, with a current target date of 2030, while at the same time evolving to be able to support other sections for the economy as they decarbonise, any and all means of facilitating research that could help achieve that end, such as identifying pathways for the electricity system' transition, and perhaps comparing their desirability or achievability, should be pursued.

DNO datasets

This work has benefitted enormously from the free and open availability of one of the DNO's (SPEN's) Open Data Portal, which went live in August 2022. Data describing load flows at 11kV level at selected locations was crucial to the work of Chapters 6,7 and 8.

Greater provision and clarity of metadata would have been useful and have facilitated more time-efficient use of these invaluable data. In particular, statements of the nature of various data fields, e.g. "measurements", "estimates", "calculated values derived from other measurements or estimates", would have been very useful, as would a statement describing which fields had been necessarily modified, for example for reasons of data security, or data protection.

Wholesale price datasets

Wholesale price datasets for GB can be purchased, for a fee, from both Nordpool and EPEX platforms, on which day-ahead and in-day trades take place. Limited excerpts from these datasets can be viewed and may be manually copied. Both platforms state that any automated download is forbidden.

Continuously-traded intraday data can be downloaded from Elexon's Market Index Data site [278]. Datasets of historical and very recent day-ahead wholesale price data covering all Entso-e-member systems, which includes GB up until the end of 2020, are available for free download from ENTSO-E's transparency platform[209] .

However there is no free and accessible data source for GB intra-day auction prices, nor for GB day-ahead prices post-Brexit. Prices sometimes differ markedly between platforms. Some means for researchers to access up-to-date these price datasets would enable more comprehensive research, and far more efficient use of researchers' time and funding.

Balancing Mechanism data

Elexon data, including Balancing Mechanism datasets detailing Final Physical Notifications, and Bid and Offer volumes and prices, can be viewed and downloaded. However their filters and downloading could be made more user-friendly.

Costs of network reinforcement

The DNOs, iDNOs and TOs within GB, all private companies, do not make their network costings publicly available. In some cases these costings may be made available to academic researchers, under an NDA-type of agreement, but such data would not be allowed to be published for public view.

This thesis has used generic costings of network reinforcement from some time ago. Even understanding that costs are likely to vary between projects, availability of average and current "rural" and "urban" costs would facilitate more realistic comparisons between the "costs of reinforcement - now", "costs of reinforcement - deferred", and any proposed alternatives.

In summary

The current barriers to data access are impeding timely and important research. The author recommends that authorities and regulators take all possible action to make the above data more freely available for other researchers.

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